UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. _________**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS RELATED TO ESTABLISHING AND COMMUNICATING SYSTEM OPERATING LIMITS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval the following proposed Reliability Standards:

- FAC-011-4 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 – Establish and Communicate System Operating Limits
- FAC-003-5 – Transmission Vegetation Management
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 – Transmission Operations

NERC also requests approval of (1) the retirement of Reliability Standard FAC-010-3 – System Operating Limits Methodology for the Planning Horizon; and (2) modifications to the

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1 16 U.S.C. § 824o (2020).
2 18 C.F.R. § 39.5.
3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")[4] to revise the definition for System Operating Limit ("SOL") and include a new term, System Voltage Limit.

NERC requests that the Commission approve the proposed Reliability Standards and NERC Glossary terms, as shown in Exhibit A, and the retirement of currently effective Reliability Standard FAC-010-3, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Violation Risk Factors and Violation Severity Levels (Exhibit G) and (ii) the proposed implementation plan (Exhibit B). As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[6] (Exhibit F), and a summary of the standard development history (Exhibit H).

This petition is organized as follows: Section I provides an introduction to the proposed modifications to NERC's Reliability Standards and the NERC Glossary. Section II provides the individuals to whom notices and communications related to the filing should be provided. Section III provides relevant background regarding the regulatory structure governing the Reliability Standards approval process and the development of the proposed Reliability Standards and NERC Glossary terms. Section IV of the petition provides justification for the proposed Reliability Standards, NERC Glossary terms, and retirements. Section IV of the petition provides a summary of the proposed implementation plan.

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4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the NERC Glossary, available at https://www.nerc.com/files/Glossary_of_Terms.pdf.

5 18 C.F.R. § 39.5(a).

6 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, at P 262, 321-37 [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

I. INTRODUCTION

The modifications proposed herein are designed to improve the framework for establishing and communicating SOLs. The use of SOLs is a foundational construct in NERC's Reliability Standards for providing for the reliable operation of the Bulk-Power System ("BPS"). Under the NERC Reliability Standards, SOLs serve as the parameters within which the Bulk Electric System ("BES") should be operated to provide for reliable pre- and post-contingency System performance. As discussed further below, SOLs constitute the Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in BES operations for monitoring and assessing pre- and post-Contingency operating states.

As approved in Order No. 817,[7] the Transmission Operations ("TOP") and Interconnection Reliability Operations ("IRO") Reliability Standards require Reliability Coordinators and Transmission Operators to plan to and operate within all SOLs, including the subset of SOLs that qualify as Interconnection Reliability Operating Limits ("IROLs"). Under those Reliability Standards, Transmission Operators and Reliability Coordinators must continually assess projected system conditions within the operations time horizon with the objective of ensuring acceptable system performance in Real-time. Specifically, Transmission Operators and Reliability Coordinators must perform Operational Planning Analyses ("OPAs"), Real-time Assessments ("RTAs"), and Real-time monitoring to assess anticipated (pre-Contingency) and potential (post-Contingency) operating conditions. The TOP/IRO Reliability Standards then require Transmission Operators and Reliability Coordinators to develop an Operating Plan to address any potential or actual SOL exceedances identified as a result of an OPA, RTA, or Real-time monitoring and, when necessary, initiate that Operating Plan to mitigate any identified SOL exceedances.

[7] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015) [hereinafter Order No. 817].

The Facilities Design, Connections, and Maintenance ("FAC") Reliability Standards include requirements for establishing and communicating SOLs and are thus integral in providing for reliable operations. The proposed Reliability Standards and NERC Glossary definitions would enhance those FAC standards by, among other things:

- providing for greater clarity and uniformity in Reliability Coordinators' SOL methodologies;
- improving the coordination between planning and operations as it relates to analysis input assumptions and System performance criteria;
- establishing a performance framework for determining SOL exceedances when performing OPAs, RTAs, and Real-time monitoring;
- clarifying functional entity responsibilities for establishing and communicating each type of SOL and IROL, consistent with the Commission's directive in Order No. 777;[8] and
- reducing redundancy and improving alignment with the Transmission Planning ("TPL"), TOP, and IRO Reliability Standards.

As discussed below, the proposed Reliability Standards and NERC Glossary terms are just, reasonable, not unduly discriminatory, and in the public interest and would enhance the framework for ensuring reliable operations.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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[8] *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 at PP 6, 41 (2013) [hereinafter Order No. 777].

III. BACKGROUND

1. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and certifying an Electric Reliability Organization ("ERO") charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[10] of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[11] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[12] of the Commission's regulations requires the ERO to file with the Commission for its approval each new Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that provide for the reliability of the BPS and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[13] and Section 39.5(c)[14] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

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[9] 16 U.S.C. § 824o.
[10] *Id.* § 824o(b)(1).
[11] *Id.* § 824o(d)(5).
[12] 18 C.F.R. § 39.5(a).
[13] 16 U.S.C. § 824o(d)(2).
[14] 18 C.F.R. § 39.5(c)(1).

2. NERC Reliability Standards Development Procedure

The proposed modifications to NERC's Reliability Standards and NERC Glossary were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process. NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual ("SPM").[15]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[16] and thus satisfy several of the Commission's criteria for approving Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees ("Board") must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

3. Development History: Project 2015-09 Establish and Communicate SOLs

The modifications to the NERC Reliability Standards and NERC Glossary proposed herein were developed in Project 2015-09 Establish and Communicate System Operating Limits ("Project 2015-09"). Project 2015-09 was initiated to address recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. That periodic review, referred to as

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[15] The NERC Rules of Procedure, including Appendix 3A, NERC Standard Processes Manual, are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[16] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

[17] Order No. 672 at PP 268, 270.

Project 2015-03 Periodic Review of System Operating Limit Standards ("Project 2015-03"), was initiated according to section 13 of the SPM.[18]

The Project 2015-03 team recommended a number of revisions to the FAC-010, FAC-011, and FAC-014 Reliability Standards intended, in large part, to align the FAC Reliability Standards with new or modified TPL, TOP, and IRO Reliability Standards that either did not exist at the time that the three FAC standards were drafted or were modified significantly since that time. The primary recommendations of the Project 2015-03 periodic review team included the following:

- Retire Reliability Standard FAC-010-3, which requires the development of an SOL methodology for the planning horizon. The periodic review team concluded the BES planning process is comprehensively covered under the new TPL-001-4 Standard.

- Revise requirements in FAC-011-3 and FAC-014-2 as the current language contributes to confusion and a lack of consistency in establishing, communicating, and operating within SOLs.

- Revise the SOL definition to align with the concepts described in the NERC System Operating Limit Definition and Exceedance Clarification White Paper developed by the standard drafting team for Project 2014-03 Revisions to TOP and IRO Standards.[19]

- Revise the requirements in FAC-011 to clarify acceptable System performance criteria for the operations horizon through the Reliability Coordinator's SOL methodology.

- Revise FAC-014-2 to delete references to planning horizon SOLs and clearly delineate specific functional entity responsibility for determining and communicating each type of SOL used in operations.

- Provide additional clarification on which SOLs qualify as IROLs.[20]

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18 Section 13 of the SPM requires that NERC review all Reliability Standards at least once every ten years to evaluate whether the Reliability Standard should be reaffirmed, revised, or withdrawn.

19 The Project 2014-03 White Paper is available at https://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf.

20 Additional information regarding Project 2015-03 is available at https://www.nerc.com/pa/Stand/Pages/Project-2015-03-Periodic-Review-of-System-Operating-Limit-Standards.aspx.

NERC initiated Project 2015-09 to evaluate the recommendations of the periodic review.[21] NERC also included within the scope of Project 2015-09 (1) FERC's directive in Order No. 777 to "establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners"[22] and (2) FERC's directive in Order No. 817 to address regional discrepancies in methods for establishing IROLs.[23]

As detailed below, the Project 2015-09 standard drafting team ("SDT") (1) developed proposed revisions to Reliability Standards FAC-011, FAC-014, IRO-008, and TOP-001-6; (2) proposed the retirement of FAC-010-3 and developed corresponding revisions in the FAC-003, PRC-002, PRC-023, and PRC-026-2 Reliability Standards to remove or replace references to SOLs established by planning entities, and (3) proposed modifications to the NERC Glossary definition of SOL and developed a new NERC Glossary term, System Voltage Limit. The NERC Board adopted the proposed Reliability Standards, NERC Glossary terms, and retirements on May 13, 2021. A summary of the development history and the complete record of development is attached to this petition as Exhibit H.

4. Order No. 817 Directive Regarding Establishing IROLs

As noted above, the scope of Project 2015-09 initially included a review of the manner in which IROLs are established to address, among other things, the regional discrepancies discussed

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[21] The Project 2015-09 Standard Authorization Request for Project 2015-09 is available at https://www.nerc.com/pa/Stand/Project%20201509%20Establish%20and%20Communicate%20System%20Op/2015-09_SAR_Revision_Clean_092717.pdf.

[22] Order No. 777 at P 41.

[23] In Order No. 817, the Commission discussed regional differences in establishing IROLs. It decided not to direct further action on IROLs in that rulemaking, finding that it should be addressed in Project 2015-09. The Commission stated that "when this issue is considered in Project 2015-19, the specific regional difference of WECC's 1,000 MW threshold in IROLs should be evaluated in light of the Commission's directive in Order No. 802 (approving Reliability Standard CIP-014) to eliminate or clarify the 'widespread' qualifier on 'instability' as well as our statement in the Remand NOPR [leading up to Order No. 817] that 'operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability.'" Order No. 817 at P 27.

in Order No. 817. The Project 2015-09 SDT considered potential revisions to the IROL definition and requirements in the FAC standards to improve consistency in the manner Reliability Coordinators establish IROLs. After many meetings with stakeholders, however, the SDT concluded that additional data, analysis, and discussion on the topic of IROLs was necessary before it could properly address the issue and reach consensus.

As a result, NERC, together with the Standards Committee, determined that it would be beneficial to develop additional technical information on the establishment of IROLs prior to engaging in any further development of modifications to the IROL definition or FAC requirements. NERC, with Standard Committee authorization, separated the IROL issues from Project 2015-09, with the exception of IROL communication issues discussed in Order No. 777, and requested that NERC's technical committees, the Operating Committee ("OC") and Planning Committee ("PC"), form a joint task force, comprised of both operating and planning subject matter experts, to develop technical material for the IROL-related issues.[24] The objective was for this technical material to be used by industry as a resource to enhance the manner in which Reliability Coordinators establish certain IROLs and inform any future Reliability Standard development activity. The OC and PC established the task force, referred to as the Methods for Establishing IROLs Task Force ("MEITF").

The MEITF has since issued a number of documents to guide industry and inform any future development activity. In September 2018, the MEITF drafted a Reliability Guideline, approved by NERC's technical committees, to provide guidance to industry on the development of technically sound methods for establishing IROLs.[25] The guideline provides detailed technical

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[24] The OC and PC have since been subsumed into the Reliability and Security Technical Committee.

[25] The Reliability Guideline is available at https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf.

reference material related to the assessment of system instability, uncontrolled separation, and Cascading to ensure the reliable operation of the BPS. Each of the three concepts related to Reliable Operation are discussed in depth, including analysis techniques and considerations that should be made when determining how they may contribute to the establishment of an IROL. Recommended practices and techniques are described using example simulations and actual system studies to clearly articulate the concepts. The various facets of establishing IROLs are described in sufficient detail to promote consistency in terminology and analysis techniques.

The MEITF also issued an IROL Framework Assessment Report, outlining alternative frameworks for establishing IROLs under the NERC Reliability Standards. It also drafted recommendations on potential changes to the NERC Glossary and Reliability Standards to align with those frameworks.[26]

At this time, NERC continues to evaluate the MEITF's framework and recommendations and monitor the impact of the MEITF's Reliability Guideline on the regional discrepancies discussed in Order No. 817. Prior to initiating any formal standards development project to consider the recommendations of the MEITF and address the outstanding directive in Order No. 817, NERC will gather additional data through its compliance monitoring activities on: (1) whether and how Reliability Coordinators have revised their methods for establishing IROLs in response to the Reliability Guideline; and (2) whether the revised methods have resulted in a more consistent approach to establishing IROLs across the BPS. If NERC observes that significant regional discrepancies persist, and those discrepancies do not appear to be justified by the unique characteristics of the region, NERC would initiate a formal standards project to evaluate those issues. As NERC gathers data and conducts this evaluation, it will consult with FERC staff.

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[26] The MEITF's proposed framework, recommendations and other documents are available at: https://www.nerc.com/comm/PC/Pages/Methods-for-Establishing-IROLs-(MEITF).aspx.

IV. JUSTIFICATION FOR APPROVAL

The proposed Reliability Standards and NERC Glossary terms meet the Commission's criteria for approval in Order No. 672 and are just, reasonable, not unduly discriminatory, and in the public interest. As discussed more fully below, the proposed standards will enhance reliability by improving the framework for establishing and communicating SOLs and improving alignment between the FAC, TPL, TOP, and IRO Reliability Standards. Collectively, the proposed modifications to the NERC Glossary and Reliability Standards support the ultimate purpose of the SOL construct: (1) establishing the applicable Facility Ratings, voltage limits, transient stability criteria, and voltage stability criteria through a common methodology, (2) ensuring that they are all observed in assessments of both the pre- and post-Contingency state when performing OPAs, RTA, and Real-time monitoring, and (3) developing and implementing Operating Plans to address any SOL exceedances observed during such assessments.[27]

1. Overview of Proposed Framework for Establishing and Communicating SOLs

The requirements to establish and communicate SOLs in the FAC-010, FAC-011, and FAC-014 Reliability Standards are inextricably linked to the TPL, TOP, and IRO standards. Each group of standards address the foundational reliability concept of planning for and ensuring

[27] As used in the proposed SOL definition and FAC standards, and the currently effective TOP/IRO standards, the pre-Contingency state is synonymous with the actual or initial state of the system. For Real-time monitoring and RTAs, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies. The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis. Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. References to the post-Contingency state or post-Contingency flows or voltages, are thus referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

acceptable system performance during operations. While the SOL definition and the FAC standards have remained essentially unchanged since their initial versions were approved in 2007, there has been significant changes to the TPL, TOP, and IRO standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with a single comprehensive planning standard, TPL-001-4;[28] all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003 Reliability Standards; and several IRO standards have been substantially modified. The proposed modifications to the NERC Glossary and Reliability Standards would enhance the framework for establishing and communicating SOLs and reflect the new constructs in the TPL, TOP, and IRO standards.

The following is an overview of the proposed framework for establishing and communicating SOLs:

Time Horizon for SOLs: To reflect the comprehensive transmission planning requirements in TPL-001-4, the proposed framework discussed in this petition would only require the establishment and use of SOLs in the operating horizon. Under currently effective Reliability Standards FAC-010-3 and FAC-014-2, each Planning Coordinator and Transmission Planner must establish a set of SOLs and IROLs for the planning time horizon based on the Planning Coordinator's SOL methodology. The Project 2015-09 SDT concluded that it was unnecessary to require planning entities to establish SOLs for the planning horizon given the comprehensive transmission planning requirements in TPL-001-4. Reliability Standard TPL-001-4 is designed to establish comprehensive Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System

[28] In Order No. 867, the Commission approved modifications to the TPL-001 standard. *Transmission Planning Reliability Standard TPL-001-5*, Order No. 867, 170 FERC ¶ 61,030 (2020). The modified version of the standard, TPL-001-5, will become effective in 2023.

conditions and following a wide range of probable Contingencies. Reliability Standard TPL-001-4 requires planning entities to establish the applicable limits or criteria for their Planning Assessments.

NERC is thus proposing to retire Reliability Standard FAC-010-3 – which relates entirely to SOLs for the planning horizon – and modify Reliability Standards FAC-003, PRC-002, PRC-023, and PRC-026 to remove or replace references to planning horizon SOLs or IROLs. To enhance alignment between planning and operations, NERC is also proposing to include requirements in proposed Reliability Standards FAC-011-4 and FAC-014-3 to improve the coordination of analysis input assumptions and System performance criteria between the Planning Assessments required in TPL-001-4 and the establishment of SOLs used in operations.

SOL Methodologies: As in the currently effective FAC Reliability Standards, the framework for establishing operating SOLs begins with the development of an SOL methodology. An SOL methodology helps ensure that SOLs are determined based on a common, established methodology across an entire Reliability Coordinator Area. Pursuant to proposed Reliability Standard FAC-011-4, Reliability Coordinators would continue to be responsible for developing a methodology for establishing SOLs (including IROLs) for use in operations in its area.

To improve uniformity in establishing SOLs, proposed FAC-011-4 improves upon the currently effective version of the standard by requiring Reliability Coordinators to provide for the following in their SOL methodologies: (1) the method for Transmission Operators to determine which Transmission Owner-provided Facility Ratings to use during operations (Requirement R2), (2) the methods to determine System Voltage Limits and stability limits (Requirements R3-R4), and (3) the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing OPAs and RTAs (Requirement R5).

NERC is also proposing a modified definition of the term SOL in the NERC Glossary to help ensure SOLs are easily identifiable and measurable, and which aligns with the SOL construct in the TOP and IRO standards. NERC proposes to define SOLs as "all Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states."

Determining SOL Exceedances: Another key component of the proposed SOL framework is setting the performance criteria used to determine SOL exceedances. Under currently effective FAC-011-3, Requirement R2, the Reliability Coordinator's SOL methodology must include a requirement that SOLs provide BES performance consistent with certain pre-Contingency performance criteria, post-Contingency performance criteria, and other rules related to the establishment of SOLs. Under this construct, assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria in Requirement R2.

These existing requirements were developed in 2007 in conjunction with the then-effective TOP/ IRO standards to create the following construct for reliable operations:

- Transmission Operators and Reliability Coordinators would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
- If the studies indicated that any of the performance criteria (in FAC-011-3, Requirement R2) were not met, the Transmission Operator would establish an SOL which, if operated within, would result in meeting all of the performance criteria.
- The Transmission Operator would then operate the system within those SOLs to ensure acceptable System performance.

Prior to April 1, 2017, when the modifications to the TOP/IRO standards approved in Order No. 817 became effective, the TOP/IRO standards did not require entities to perform assessments of the post-Contingency state in same-day or Real-time operations. The requirements associated with assessments of the post-Contingency state were essentially folded into the SOL establishment process – i.e., the establishment of SOLs that "provide" for meeting the pre- and post-Contingency performance criteria in FAC-011-3, Requirement R2.

The currently effective TOP/IRO standards, however, provide a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct, Transmission Operators and Reliability Coordinators are required to perform OPAs in the day-ahead time frame to assess whether the planned operations for the next day will exceed any of SOLs or IROLs.[29] The pre- and post-Contingency states are analyzed as part of the OPA. If the OPA identifies any potential SOL exceedances, the Transmission Operator and Reliability Coordinator must have an Operating Plan to address those exceedances.[30]

In Real-time, Transmission Operators and Reliability Coordinators must perform RTAs at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[31] The pre- and post-Contingency states are analyzed as part of the RTA. If a Transmission Operator observes an SOL exceedance in its Real-time monitoring or RTA, the Transmission Operator is required to implement its Operating plan to mitigate the conditions.[32] If a Reliability Coordinator observes an SOL or IROL exceedance in its Real-time monitoring or RTA, the Reliability Coordinator is required to notify the relevant Transmission Operators of the exceedance so the Transmission Operator can address it.[33] If the Reliability Coordinator identifies an expected or actual IROL exceedance in its Real-

29 IRO-008-3, Requirement R1; TOP-002-4, Requirement R1.
30 IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.
31 IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.
32 TOP-001-3, Requirement R14.
33 IRO-008-2, Requirement R5.

time monitoring or RTA, the exceedance must be resolved within the IROL Tv, which can be no longer than 30 minutes.[34]

Accordingly, pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, Transmission Operators and Reliability Coordinators must continually assess system conditions, identify expected or actual SOL exceedances (including IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. The pre- and post-Contingency states are thus assessed on an ongoing basis as part of OPAs and RTAs.

To align with this new construct, proposed FAC-011-4, Requirement R6 requires Reliability Coordinators to include in their SOL methodologies a specified performance framework to determine SOL exceedances when performing Real-time monitoring, RTAs, and OPAs. The proposed performance framework would help ensure there is consistency in determining what constitutes an SOL exceedance during operations. The performance framework maps to and clarifies the performance criteria in currently effective FAC-011-3, Requirement R2.

NERC is also proposing new requirements in IRO-008-3 and TOP-001-6 to require Reliability Coordinators and Transmission Operators to use the SOL exceedance performance framework in the Reliability Coordinator's SOL methodology when performing Real-time monitoring, RTAs, and OPAs. Additionally, under proposed FAC-011-4, to ensure that SOL exceedances are communicated in a timely manner, the Reliability Coordinator must also include in its SOL methodology a risk-based approach for determining how and when SOL exceedances identified as part of Real-time monitoring and RTAs must be communicated.

[34] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

Communicating SOL Methodologies: The next step in the process of establishing SOLs is for the Reliability Coordinator to distribute its SOL methodology to the appropriate entities, namely, those entities responsible for developing SOLs within the Reliability Coordinator Area and those that should otherwise have awareness of the manner in which SOLs are developed in that area given their functional obligations. As discussed below, proposed FAC-011-4, Requirement R9 specifies the entities to which the Reliability Coordinators must provide its SOL methodology and the timeframe for doing so.

Responsibility for Establishing SOLs: Once the Reliability Coordinator develops and communicates the SOL methodology, the next part of the framework is for the appropriate entities to use that methodology to establish the SOLs used in operations. Proposed Reliability Standard FAC-014-3 delineates the functional entities responsible for establishing and communicating each type of SOL. As discussed further below, each Transmission Operator is obligated to establish SOLs for its portion of the Reliability Coordinator Area, with one exception. The Reliability Coordinator is responsible for establishing stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area. Reliability Coordinators are also responsible for establishing IROLs for its area.

Responsibility for Communicating SOLs: The last element of the proposed framework is communicating the established SOLs. Under proposed Reliability Standard FAC-014-3, each Transmission Operator must provide its SOLs to their Reliability Coordinator. In turn, Reliability Coordinators are responsible for providing the SOLs (including IROLs) for its area to Planning Coordinators, Transmission Planners, and Transmission Operators. The proposed requirements improve upon the current standards by clarifying when the Reliability Coordinator is responsible for such communications. The proposed requirement addresses both the content and the frequency at which the information must be provided and complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information.

The following is a more detailed discussion of each of the proposed modifications to the NERC Glossary and Reliability Standards.

2. Proposed Modification to Definition for System Operating Limit

The proposed SOL definition is designed to provide greater clarity and consistency in establishing SOLs.[35] The Project 2015-9 SDT found that although use of SOLs is a foundational concept in NERC's Reliability Standards, there were significant discrepancies in registered entities' understanding and application of SOLs. SOL is currently defined as:

> The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
> - Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)
> - transient stability ratings (applicable pre- and post- Contingency stability limits)
> - voltage stability ratings (applicable pre- and post-Contingency voltage stability)
> - system voltage limits (applicable pre- and post-Contingency voltage limits).

The Project 2015-09 SDT proposed the following SOL definition to eliminate ambiguities and provide for a more straightforward approach to facilitate a more consistent application of the SOL concept across the electricity industry:

> All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

[35] Available at https://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf.

The proposed definition retains Facility Ratings, voltage limits, and stability limits as the types of operating parameters that would be categorized as SOLs. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. For voltage limits, the proposed SOL definition uses a new term proposed to be incorporated into the NERC Glossary, System Voltage Limit. As discussed further below, the proposed definition for System Voltage Limit is "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Proposed FAC-011-4 addresses the method for determining System Voltage Limits to be used in operations.

Stability limits includes both transient stability limits and voltage stability limits as in the currently effective definition. NERC proposes to use the undefined term "stability limit," as opposed to the NERC Glossary term "Stability Limit," to allow entities to use different types of stability-related limitations or phenomena, including, but not limited to, subsynchronous resonance, phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio. The NERC Glossary term "Stability Limits" is limited to a maximum power flow value. While some entities use maximum power flow values as a means by which to prevent instability, this approach represents one method and may be too restrictive for some entities. Reliability tools provide entities the ability to monitor and control parameters other than maximum power flow to demonstrate acceptable stability performance.

The proposed SOL definition also retains the reference to "specified system configuration." Stability limits are typically dependent on system configuration and, although not typical, Facility Ratings and System Voltage Limits may also be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for the line could be reduced due to the current carrying capability of the remaining in-service circuit breaker.

There are a number of key differences between the currently effective SOL definition and the proposed definition. Whereas the currently effective SOL definition states that SOLs "are based upon certain operating criteria," the proposed definition clarifies that SOLs "are" the actual operating parameters to be observed for the pre- and post-Contingency states. This change helps eliminate confusion as to whether a Facility Rating, stability limit, or voltage limit is an SOL.

In contrast to the existing definition, the proposed definition also includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning from those used in operations. As discussed below, NERC is proposing to retire FAC-010-3 and the requirements related to the establishment and communication of planning horizon SOLs. The SDT concluded that planning horizon SOLs are unnecessary given the comprehensive planning requirements in TPL-001-4. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there is no additional reliability need to require planning entities to develop SOLs to be used in the planning horizon.

NERC also proposes removing the "most limiting criteria" concept from the SOL definition. Under the modified definition, all Facility Ratings, System Voltage Limits, and stability limits are considered SOLs. This change aligns with the requirements in the TOP/IRO Reliability Standards. As noted above, under those standards, each Reliability Coordinator and Transmission Operator must perform OPAs and RTAs to assess conditions in the day-ahead and Real-time time horizons. The currently effective SOL definition requires Reliability Coordinators and Transmission Operators to initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT found that this construct was unnecessary and caused confusion within industry as the most limiting criteria (and thus the SOL) could change from one RTA to the next.

The SDT determined that a more straightforward approach – categorizing all Facility Ratings, System Voltage Limits, and stability limits as SOLs – would align more clearly with the TOP/IRO standards. In performing OPAs and RTAs, Reliability Coordinator and Transmission Operator should be assessing conditions as it relates to all of these operating parameters or reliability limits, not just the most limiting parameter or limit based on a particular prior analysis. In assessing conditions to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, Reliability Coordinators and Transmission Operators would capture the most limiting of those parameters/limits. The "most limiting criteria" concept is thus subsumed within the IRO/TOP requirements and it is not necessary that it be included in the SOL definition.

The "most limiting criteria" in the SOL definition could also mask instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot safely conclude that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria," it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the Reliability Coordinator and its

Transmission Operators have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL methodology.

NERC also proposes to remove the "acceptable reliability criteria" concept from the SOL definition. The SDT concluded that acceptable reliability criteria is best addressed in the body of the Reliability Standards and the SOL definition should focus exclusively on what constitutes an SOL. Operations performance criteria is addressed in proposed FAC-011-4, Requirement R6.

Last, the proposed SOL definition retains the pre- and post-Contingency concept, although the reference is modified to align with the construct in the currently effective TOP/IRO standards. The proposed definition recognizes that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances and actual SOL exceedances, respectively, the definition of SOL should support the concept that entities must account for both the pre- and post-Contingency states.

3. Proposed NERC Glossary Term System Voltage Limit

NERC also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

The proposed definition would help provide for a uniform understanding as to what constitutes a system voltage limit. The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single maximum and minimum limit that is applicable to its entire system. Rather, as explained below, under proposed FAC-011-4, Requirement R3, the Reliability Coordinator's SOL methodology would dictate the manner in which System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to provide flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL methodology. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. Last, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating because proposed FAC-011-4, Requirement R3 requires that System Voltage Limits respect voltage-based Facility Ratings.

4. Proposed Retirement of Reliability Standard FAC-010-3 and Modifications to Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2

As noted above, NERC is proposing to retire Reliability Standard FAC-010-3 to remove the requirements that Planning Coordinators and Transmission Planners establish SOLs for the planning horizon. This section explains the rationale for the proposed retirement and describes the modifications to Reliability Standards FAC-003, PRC-002, PRC-023, and PRC-026 to remove or replace references to planning horizon SOLs or IROLs. This section also provides the rationale for not proposing modifications to Reliability Standards CIP-002-5.1a or CIP-014-2, although those standards also reference planning horizon IROLs. As explained below, the retirement of FAC-010-3 is not dependent on modifying those Critical Infrastructure Protection ("CIP") standards. Given the unique expertise required for the CIP standards, it is prudent to allow a CIP-specific SDT to address any conforming changes to those standards.

i. Retirement of FAC-010-3

As noted above, the SDT concluded that the requirements related to the establishment and communication of planning horizon SOLs in FAC-010-3 and FAC-014-3 were unnecessary for reliability given the comprehensive planning requirements in TPL-001-4. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 (Facility Ratings) and TPL-001-4 (voltage limits, and stability criteria). As a result, there was no additional reliability need to require Planning Coordinators and Transmission Planners to develop SOLs to be used in the planning horizon.

Exhibit D-1 to this petition provides a mapping of the existing requirements in FAC-010-3 to TPL-001-4. As illustrated therein, all of the reliability issues that FAC-010-3 was intended to cover have since been addressed in TPL-001-4, as follows:

FAC-010-3, Requirement R1 requires Planning Authorities to have a methodology for developing SOLs within its area applicable to the planning horizon. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the planning horizon, however, are now fully addressed in TPL-001-4:

- Facility Ratings – TPL-001-4, Requirement R1, requires Planning Coordinators and Transmission Planners to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1. Facility Ratings, as determined under FAC-008-3, are included in this data.
- System Steady-State Voltage Limits – TPL-001-4, Requirement R5 requires the Transmission Planner and Planning Coordinator to have criteria for acceptable System steady state voltage limit to be used in the Planning Assessments.

- Transient and Voltage Stability Performance Criteria – TPL-001-4, Requirement R6 requires the Transmission Planner and Planning Coordinator to have documented criteria to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

FAC-010-3, Requirement R1 also requires Planning Authorities to include in their SOL methodologies a description of how to identify IROLs, which is defined as an SOL "that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." While TPL-001-4 does not use the term IROL, the functional equivalent of IROLs must be identified in the Planning Assessment. TPL-001-4, Requirement R6 requires Planning Coordinators and Transmission Planners to document criteria or a methodology for use in identifying System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. The Planning Assessment is shared with impacted Reliability Coordinators, per IRO-017-1 Requirement R3. Additionally, the Planning Assessment must identify instances of instability, Cascading or uncontrolled separation. The identified instances must be communicated to the Reliability Coordinator in accordance with FAC-014-3, Requirement R7 along with additional information about those instances.

FAC-010-3, Requirement R2 requires that the Planning Authority's SOL methodology include a requirement that SOLs provide BES performance consistent with certain specified criteria. The specified criteria maps to the performance requirements contained in Table 1, notes a–j, of TPL-001-4. The Table 1 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment. As demonstrated in Exhibit D-1, the FAC-010-3 pre-Contingency performance criteria, the post-Contingency performance criteria, and other rules are addressed in Table 1 of TPL-001-4.

FAC-010-3, Requirement R3 requires that the SOL methodology include a description of the following: study model, selection of applicable Contingencies, level of detail of system models used to determine SOLs, allowed uses of Remedial Action Schemes, anticipated transmission system configuration, generation dispatch and Load level, and the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL Tv. As demonstrated in Exhibit D-1, each of these items is covered in TPL-001-4.

FAC-010-3, Requirement R4 requires the Planning Authority to provide its SOL methodology, and any change thereto, to adjacent Planning Authorities, other Planning Authorities with a reliability-related need for it, Reliability Coordinators and Transmission Operators that operates any portion of the Planning Authority Area, and Transmission Planners in the Planning Authority Area. The TPL-001-4 Planning Assessment must also be distributed to those same planning entities (under TPL-001-4, Requirement R8) and impacted Reliability Coordinators (under IRO-017-1, Requirement R3). Other entities with a reliability-related need, which reasonably includes Transmission Operators, among others, may also receive the Planning Assessment (under TPL-001-4, Requirement R8).

While TPL-001-4 obviates the need for planning horizon SOLs, the SDT concluded there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT therefore developed requirements in proposed Reliability Standards FAC-011-4 and FAC-014-3 to address that issue. Those requirements, discussed in greater detail in Section IV.5-6 below, enhance the coordination of analysis input assumptions and System performance criteria between the Planning Assessments required in TPL-001-4 and the establishment of SOLs to be used in operations.

i. Proposed Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2

With the proposed retirement of FAC-010-3, NERC is also proposing modifications to the FAC-003, PRC-002, PRC-023, and PRC-026 Reliability Standards to remove or replace references to planning horizon SOLs or IROLs. The following is a description of the modifications in proposed Reliability Standards FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2.

FAC-003-5 – NERC proposes to modify Applicability Sections 4.2.2 and 4.3.1.2 of FAC-003-5 to replace references to "elements of an IROL under NERC Standard FAC-014 by the Planning Coordinator" with references to facilities:

> identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

The reference to facilities "that if lost or degraded are expected to result in instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System" is the functional equivalent to referencing elements of a planning horizon IROL. An IROL is defined as a SOL "that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Additionally, NERC is proposing to delete the language referencing planning horizon SOLs from Requirement R1, as follows:

> Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s)~~, which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all Rated Electrical Operating Conditions of the types shown below.

NERC is also proposing to delete Requirement R2 in its entirety as it is redundant to Requirement R1. Requirements R1 and R2 are essentially the same requirements but apply to different Facilities. These requirements were initially separate to recognize that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a result, the Violation Risk Factor ("VRF") was set at "high" for Requirement R1 and "medium" for Requirement R2. In FERC Order 777, however, FERC directed NERC to change the VRF for Requirement R2 from "medium" to "high" because transmission lines that were not part of an IROL or Major WECC Transfer Path contributed to cascading outages in the past.[36] This removed the only difference between the two Requirements R1 and R2, resulting in redundancy between the two requirements. NERC is therefore proposing the retirement of Requirement R2 with the modifications to Requirement R1 to apply to all applicable facilities.

PRC-002-3 – NERC proposes to modify the applicability of the PRC-002 standard to remove Planning Coordinators as a responsible entity subject to the standard and replace any references in the standard that would have included Planning Coordinators with references to Reliability Coordinators. The SDT concluded that the Reliability Coordinator was the appropriate entity to carry out the duties that currently apply to Planning Coordinators in certain interconnections, including the identification of BES elements that are part of an IROL or stability-related SOL.

PRC-023-5 – NERC proposes to modify Section B2 of Attachment B to PRC-023-5 as follows:

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[36] Order No. 777 at P 77.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events. ~~The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

Attachment B sets the criteria used to determine the circuits in a Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with certain requirements in the standard applicable to protective relays.

PRC-026-2 – NERC proposes modification to the PRC-026 standard to replace references to planning horizon SOLs with references to the TPL-001-4 Planning Assessment, as follows:

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner:

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator ~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. ~~An~~ Elements associated with ~~that is monitored as part of an SOL identified by the Planning Coordinator's methodology based~~ on an angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event ~~constraint~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance for a planning event. [footnote omitted]

ii. CIP-002 and CIP-014

As noted above, both CIP-002-5.1a and CIP-014-2 reference planning horizon IROLs. The CIP-002 Reliability Standard requires entities to identify and categorize their BES Cyber Systems as high, medium, or low impact based on the criteria set out in Attachment 1 to the standard. Criterion 2.6 in Attachment 1 provides that BES Cyber Systems associated with the following should be categorized as medium impact:

> Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

Similarly, the applicability section for CIP-014 provides that a Transmission Owner that owns a substation that meets the following criteria, among others, is subject to the standard:

> 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

At this time, however, NERC is not proposing modifications to Reliability Standards CIP-002-5.1a or CIP-014-2 to remove or replace references to planning horizon IROLs. Given the unique expertise required for the development of CIP standards, it is prudent to allow a CIP-specific SDT to address any conforming changes to those standards as it considers other changes to the CIP-002 criteria and CIP-014 applicability.[37] When the NERC Board adopted the modifications proposed herein, it directed NERC staff to evaluate the need for conforming changes in CIP-002 and CIP-014.

[37] NERC initially posted for comment and ballot proposed conforming changes to the CIP-002 and CIP-014 standards to replace references to planning IROLs. The proposal for CIP-002 did not garner sufficient stakeholder support from the Registered Ballot Body. Based on stakeholder comments, NERC determined it was prudent to delay consideration of any such changes until a CIP-specific SDT was considering CIP-002 changes.

On June 2, 2021, the Project 2015-09 SDT submitted a SAR to the NERC Standards Committee to initiate a formal development project to assess the need for any conforming changes to CIP-002 or CIP-014. The Standards Committee may add it to the scope of Project 2021-03, which is currently addressing modifications to CIP-002, or initiate a separate project.

As explained in Exhibit C-7, the retirement of FAC-010-3 may proceed prior to making any conforming changes to CIP-002 or CIP-014. The retirement of FAC-010-3 is not expected to decrease the protections of critical facilities under the CIP standards. Under the proposed FAC Reliability Standards, the Reliability Coordinator remains responsible for establishing IROLs for use in operations and would thus continue to identify transmission and generation facilities critical to the derivation of those IROLs and their associated contingencies under Criterion 2.6 in Attachment 1 to the CIP-002 Reliability Standard and for CIP-014 applicability.

Proposed FAC-014-3 would enhance that identification in two ways. First, the proposed modifications in FAC-014-3 would help ensure that the Reliability Coordinator's identification of IROLs is informed by reliability risks identified by Planning Coordinators and Transmission Planners under TPL-001-4. Specifically, pursuant to proposed FAC-014-3, Requirements R7 and R8, Planning Coordinators and Transmission Planners must share with impacted Reliability Coordinators information on any instability identified in a TPL-001-4 Planning Assessment and the associated Corrective Action Plan ("CAP").[38] This sharing would include "their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES." These requirements

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[38] Under TPL-001-4 Requirement, R3, Parts 3.4 and 3.5, and Requirement R4 Parts 4.4 and 4.5, Planning Coordinators and Transmission Planners must identify and create a list of the planning and extreme events that are expected to produce "more severe System impacts." These events may significantly overlap with those events that are critical to the derivation of an IROL as they are based on the components of the IROL definition (instability, Cascading, and uncontrolled separation that adversely impact the reliability of the BES) to describe the relevant Facilities as opposed to using the term itself.

would thus provide the Reliability Coordinator with additional relevant information it needs from planning entities in its determination of IROLs. From a CIP perspective, because of this improved communication, the Reliability Coordinator's list of facilities critical to the derivation of IROLs would likely cover many of the facilities that would have otherwise been identified by planning entities under Criterion 2.6 in Attachment 1.

Second, proposed FAC-014-3, Requirement R5, part 5.6, would require the Reliability Coordinator to provide each impacted Generator Owner or Transmission Owner with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. This requirement does not currently exist. There is currently no requirement that the information described in Attachment 1 of CIP-002.5.1a be provided to Transmission Owners or Generation Owners. Proposed FAC-014-3, Requirement R5, Part 5.6 fills that gap by requiring the Reliability Coordinator to provide the information on a regular basis. This requirement addresses the concern in Order No. 777 regarding providing such information to asset owners subject to the CIP standards. With an annual submission, the Reliability Coordinator should be able to provide the required information whether the data is created in an annual process (such as seasonal studies), or some other effort with a higher periodicity.[39]

The retirement of FAC-010-3 is also unlikely to decrease the level of CIP protection as many of the facilities that would have been identified by Planning Coordinators and Transmission Planners under Criterion 2.6 are also covered by other criteria in Attachment 1 to CIP-002-5.1a

[39] Additionally, pursuant to TPL-001-4, Requirement R8, Transmission Owners and Generation Owners may request the Planning Assessment from the relevant planning entity. The Planning Assessment will include a list of the planning and extreme events that are expected to produce "more severe System impacts." There would likely be significant overlap between the facilities relevant to those events and those that planning entities would have identified as critical to the derivation of an IROL under Criterion 2.6.

and the applicability of CIP-014-2. Criterion 2.3, for instance, covers generation Facilities identified by Planning Coordinators and Transmission Planners as necessary to avoid an Adverse Reliability Impact. The definition of Adverse Reliability Impact is "the impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." Given the similarity with the definition of IROL, there is significant overlap between the generation Facilities subject to Criterion 2.3 and those that the Planning Coordinators and Transmission Planner would identify as critical to the derivation of an IROL under Criterion 2.6.

Criterion 2.4 requires BES Cyber Systems associated with Transmission Facilities operated at 500 kV or greater voltages to be in the medium impact category. As these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than lower voltage Facilities. This criteria also significantly overlap with the Facilities that planning entities would have otherwise identified under Criterion 2.6.

Criterion 2.5, which is also in the applicability of CIP-014, applies to Transmission Facilities operating between 200 kV and 499 kV based on the number of connections to other Transmission stations or substations. The basic premise of this criterion is to categorize BES Cyber Systems associated with "well-connected" BES substations as medium impact. As these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than Facilities not as well connected to the System. This criteria would thus largely overlap with the Facilities that would otherwise be identified by planning entities under Criterion 2.6.

For these reasons, the retirement of FAC-010-3 would not result in any gap in the CIP standards. Consistent with the NERC Board's directive, however, NERC will initiate its stakeholder processes to evaluate conforming changes to remove or replace references to planning horizon IROLs in CIP-002 and CIP-014.

5. Proposed Reliability Standard FAC-011-4

The purpose of the FAC-011 Reliability Standard is to "ensure that [SOLs] used in the reliable operation of the [BES] are determined based on an established methodology or methodologies." The following is a description of each of the requirements of proposed FAC-011-4 and a discussion of the changes from the previous version of the standard.

<u>Requirement R1</u>: As in the currently effective version of FAC-011, proposed Reliability Standard FAC-011-4, Requirement R1 requires Reliability Coordinators to "have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area." The remaining requirements in the proposed standard address the contents and communication of that methodology.

As described in the SDT's technical rationale (Exhibit C-1) and mapping document (Exhibit D-1) for proposed FAC-011-4, Requirement R1 does not include the three subparts in the current version. Those subparts are either not necessary for reliability, or they are addressed in other requirements in proposed FAC-011-4, as follows:

- Part 1.1 in the effective version, which specifies that the SOL methodology "be applicable for developing [SOLs] used in the operations horizon," is not necessary as the revised Requirement R1 already specifies that it is applicable to the Operations Planning Time Horizon.

- Part 1.2 in the effective version, which requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings," is addressed in proposed Requirement R2.

- Part 1.3 in the effective version, which requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs," is now addressed in proposed Requirement R8.

Requirement R2: Proposed Requirement R2 addresses Facility Ratings, and provides:

> Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

The FAC-008 Reliability Standard governs the establishment of Facility Ratings, requiring Transmission Owners and Generation Owners to establish Facility Ratings in accordance with a specified methodology and communicate those ratings to relevant entities. The reliability objectives of proposed FAC-011-4, Requirement R2 is to ensure that Reliability Coordinators and their Transmission Operators use the same owner-provided Facility Ratings in operations. For example, if a Transmission Owner provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another Transmission Owner provides five levels of ratings, proposed Requirement R2 instructs the Reliability Coordinator to establish the method for determining which of those Facility Ratings must be used in operations for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner remains the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to ensure that those owner-provided Facility Ratings are used consistently between Reliability Coordinators and their Transmission Operators during operations.

Requirement R3: The reliability objective of proposed Requirement R3 is to ensure that System Voltage Limits are determined according to an established method that meets certain criteria. The currently effective version does not include such a requirement. Requirement R3 provides as follows:

> **R.3.** Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the minimum allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

Requirement R3 Part 3.1 provides that each BES bus/station have an associated System Voltage Limit, unless otherwise specified in the SOL methodology. The SDT concluded that while all BES buses/stations have equipment-related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from maximum voltage, and the System from instability, voltage collapse, and misactuation of relay elements.[40]

Requirement R3 Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or Transmission Owner under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based

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[40] The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Facility Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

Requirement R3 Part 3.3 provides that the SOL methodology shall ensure that System Voltage Limits are not set at values less than Undervoltage Load Shedding ("UVLS") settings to avoid UVLS operation following N-1 Contingencies. This requirement is designed to be consistent with Order No. 818, which states that UVLS should not be triggered for an N-1 Contingency,

Requirement R3 Part 3.4 ensures that minimum limits are provided. Maximum limits tend to be associated with equipment/facility limitations whereas minimum limits are often used to prevent phenomena associated with minimum voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits," both maximum and minimum, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used. It also provides the Reliability Coordinator the authority to ensure that Transmission Operators establish System Voltage Limits in a manner that supports System reliability (in the context of system voltage performance).

Part 3.5 requires that the SOL methodology define a method for determining common System Voltage Limits. Entities may independently identify System Voltage Limits, which, if not coordinated, could create reliability issues. For example, one Transmission Operator may choose very wide System Voltage Limits on its equipment while another Transmission Operator may choose much tighter System Voltage Limits even within the same substation. The Transmission Operator with wider System Voltage Limits may operate equipment that are within its System Voltage Limits but cause an exceedance of the other Transmission Operator's equipment limits.

Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Requirement R4: The reliability objective of proposed Requirement R4 is to ensure that stability limits are determined according to an established method that meets certain criteria. The currently effective version does not include such a requirement. Requirement R4 provides as follows:

> **R4.** Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:
>
> 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:
>
> 4.1.1. steady-state voltage stability;
> 4.1.2. transient voltage response;
> 4.1.3. angular stability; and
> 4.1.4. System damping.
>
> 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.
>
> 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.
>
> 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.
>
> 4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.
>
> 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.
>
> 4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

While the currently effective version of the FAC-011 standard requires that the System demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, it does not provide any specific stability criteria as in proposed Requirement R4, Part 4.1. Requiring specific stability criteria within the SOL methodology improves the standard as it provides greater clarity and uniformity in practices across the industry.

Requirement R4 Part 4.1 also requires that the SOL methodology include descriptions of margins applied. This language provides additional awareness of the Reliability Coordinator practices for offline or on-line calculated stability limits, including any margin used in the application of the stability limits. The Reliability Coordinator has discretion as to the type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 requires that stability limits meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. As discussed below, Requirement R5 sets out the minimum set of Contingencies that entities must use in establishing stability limits.

Requirement R4 Part 4.3 is designed to help clarify how Reliability Coordinators will establish stability limits when the instability impacts multiple Transmission Operators within a Reliability Coordinator Area or adjacent Reliability Coordinator Areas. The SOL methodology could describe the manner in which the Reliability Coordinator establishes the stability limit through its technical analysis, or the method its uses to coordinate and choose between stability limits derived by multiple Transmission Operators.

Requirement R4 Parts 4.4-4.5 require that the SOL methodology provide a description of the key parameters or elements that must be considered and monitored when determining stability limits. These requirement parts would help ensure that the SOL methodology provides enough information to allow entities to consistently use the same method for determining stability limits.

For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e., winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow Transmission Operators and other entities to consistently duplicate results from study to study.

Requirement R4 Part 4.4 addresses the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the OPAs and RTAs for which they will be used. As stability limits may vary based on system topology, load, generation dispatch, etc., the stability limits used in OPAs and RTAs should be "valid" or applicable for those system conditions.[41] The description of system conditions for the applicable stability limits required by Part 4.4 allows the use of these limits in OPAs and RTAs for the defined system conditions.

Requirement R4 Part 4.5 combines Parts 3.1 and 3.4 in the currently effective version of FAC-011 into a single requirement part. It provides Reliability Coordinators flexibility to reflect the varying needs for different types of stability limits within its footprint (e.g., local single unit stability up to wide area or inter area instability). By recognizing that certain types of localized stability issues may not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, the proposed revision recognizes the ability to monitor these localized areas with real-time stability analysis tools.

Requirement R4 Parts 4.6 and 4.7 address how the SOL methodology accounts for Remedial Action Schemes ("RAS"), UFLS, and UVLS. Part 4.6 requires that the SOL methodology describe allowed uses of RAS and other automatic post-Contingency mitigation

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[41] The definitions for OPA and RTA include "[a]n evaluation of… system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for… operations,"

actions in establishing stability limits. In contrast, Part 4.7 expressly prohibits the consideration of UFLS or UVLS Programs as an acceptable post-Contingency mitigation action. This prohibition preserves the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation," consistent with Order No. 763.[42]

Requirement R5: Proposed Requirement R5 addresses the Contingency events for use in determining stability limits and performing OPAs and RTAs, combining the requirements for single Contingencies (formerly FAC-011-3, Requirement R2, Part 2.2) and for multiple Contingencies (formerly of FAC-011-3, Requirement R3 Part 3.3). Proposed Requirement R5 provides:

> **R5.** Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:
>
> 5.1. Specify the following single Contingency events
>
> 5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:
>
> - generator;
> - transmission circuit;
> - transformer;
> - shunt device; or
> - single pole block in a monopolar or bipolar high voltage direct current system.
>
> 5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.
>
> 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in

[42] As described within PRC-006-2 in alignment with FERC Order No. 763, UFLS programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures."

> accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Requirement R5 Part 5.1 identifies the minimum set of single Contingencies that entities must use in establishing stability limits and performing OPAs and RTAs. As in the current version of the standard (FAC-011-3, Requirement R2 Part 2.2 and Requirement R3 Part 3.3), proposed Requirement R5 Part 5.2 provides the Reliability Coordinator the flexibility to determine which additional single and multiple Contingencies to respect given the unique characteristics of its system. For instance, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the risk related to such an event is relevant in the Reliability Coordinator Area.

Requirement R5 Part 5.3 provides a link between planning and operations by ensuring that the Reliability Coordinator's SOL methodology describes the manner in which the Contingency event information the Planning Coordinator provides under FAC-014-3, Requirement R7 is used in deriving stability limits for operations.

<u>Requirement R6</u>: Proposed Requirement R6 establishes the performance framework for determining SOL exceedances when performing OPAs, RTAs, and Real-time monitoring. The proposed performance framework would enhance consistency across the industry in determining what constitutes an SOL exceedance during operations. The proposed performance framework is designed to align with the SOL construct in the TOP/IRO standards and reflect the concepts in the Whitepaper on System Operating Limit Definition and Exceedance Clarification ("SOL Whitepaper"), included as Exhibit E hereto.

Proposed Requirement R6 provides:

> **R6.** Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities are within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made. [footnotes omitted]

An SOL exceedance would occur if, in the assessment of pre- and post-Contingency conditions, this performance framework is not met. In Real-time operations, SOL exceedances are determined through Real-time monitoring and RTAs, while in the day-ahead, potential SOL exceedances are determined through OPAs. For Facility Ratings and System Voltage Limits, SOL exceedances are identified through the evaluation of the pre-Contingency state and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

Requirement R6 Part 6.1 sets out the framework for System performance for no contingencies and Part 6.2 sets out the framework for System performance for the single contingencies listed in Part 5.1. For each of these scenarios, Parts 6.1-6.2 prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual or expected flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits. The following is a discussion of how these requirement parts would apply to each type of SOL.

Facility Rating Exceedance: As discussed in the SOL Whitepaper, Facility Ratings include Normal Ratings and one or more Emergency Ratings. Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life. Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or RTAs. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet the performance framework articulated in Requirement R6 Part 6.1.1. The use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition.[43]

Requirement R6 Part 6.2.1 provides "Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating" to address the scenario where the System Operator has insufficient time to implement post-Contingency mitigation actions (i.e., actions taken after the Contingency event occurs). The language in Part 6.2.1 provides that exceeding the highest Emergency Rating will be identified as an SOL exceedance, resulting in the Transmission Operator taking pre-Contingency mitigation actions consistent with the Operating Plan as soon as possible to address the condition.

System Voltage Limit Exceedance: System performance for System Voltage Limits is determined through OPAs and RTAs. Normal and emergency maximum and minimum System Voltage Limits are required to be established by the Transmission Operator in accordance with the Reliability Coordinator's SOL methodology. Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are typically applicable for the post-Contingency state. As provided in Requirement R6 Part 6.1.2 and 6.2.2, System Voltage Limits are exceeded when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when an RTA indicates that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event.

Stability Limit Exceedance: Transient and voltage stability limits can be determined through prior studies, or they can be determined in Real-time. Transient stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that

[43] The SOL Whitepaper provides additional detail on the performance framework for Facility Ratings and illustrates how the framework would apply to different scenarios.

the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism. Though voltage stability limits can be determined, expressed, and monitored in several ways, the general principle is universal: voltage stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency from resulting in instability. Requirement R6 Parts 6.1.3 and 6.2.3 articulate this concept. Part 6.1.3 provides that when there is no Contingency, acceptable System performance occurs when operation is within all pre-determined stability limits. Part 6.2.3 provides that acceptable System performance for the single contingencies listed in Requirement R5 occurs when all stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.

Requirement R6 Parts 6.1.4, 6.2.3, and 6.2.4 include a footnote that states, "Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques." This footnote acknowledges that there are multiple methods to assessing whether System performance demonstrates Instability, Cascading, or uncontrolled separation that adversely impact the reliability of the BES. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA, and Real-time monitoring. Other entities use tools that run at the time of the OPA or RTA to assess acceptable performance or determine stability limits. Others use other offline analysis techniques.

Requirement R6 Part 6.3 addresses System performance for the multiple contingencies the Reliability Coordinators identify under Requirement R5 that are more severe than the single Contingency events. Per Part 6.3, if any of the more severe Contingency events were to occur, the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation.

Requirement R6 Part 6.4 retains the requirement in currently effective FAC-011-3 Requirement R2, Part 2.3.2 and articulated in Order No. 705 that System Operators may only use load shedding as a measure of last resort to prevent cascading failures. Part 6.4 provides that Operating Plans may only provide for load shedding after other available system adjustments have been made. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan.

Requirement R7: The reliability objective of proposed Requirement R7 is to ensure that SOL exceedances are communicated to the relevant entities in a timely manner. Proposed Requirement R7 provides:

> **R7.** Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include:
>
> 7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.
>
> 7.1.1 IROL exceedances;
>
> 7.1.2 SOL exceedances of stability limits;
>
> 7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

The risk-based approach in proposed Requirement R7 is designed to require entities to communicate only those SOL exceedances deemed material to reliable operations. The SDT concluded that it would be overly burdensome and unnecessary for Transmission Operators to communicate every SOL exceedance identified in an RTA or during Real-time monitoring as many of those will be of a short duration (e.g., less than 15 min) and routinely resolved by the Transmission Operator or market signals. Proposed Requirement R7 therefore provides the Reliability Coordinator the authority to develop a risk-based approach for communicating SOL exceedances. Part 7.1, however, establishes the minimum set of SOL exceedances that must always be communicated, regardless of duration, given their likelihood to have a material impact on operations. The Reliability Coordinator has discretion to set the timeline for such communication.

Additionally, Requirement R7 Part 7.2 lists those types of SOL exceedances that must be communicated if not resolved within 30 minutes. The SDT concluded that while the subset of SOL exceedances listed in Part 7.2 presented a lower risk than those listed in Part 7.1, they should always be communicated as their risk profile increases if they persist for a longer duration. The Reliability Coordinator's methodology must specify the timeframe within which these types of SOL exceedances must be communicated.

As discussed further below, NERC is proposing modifications to TOP-001-5, Requirement R15, and IRO-008-3, Requirements R5 and R6 to provide that communication of SOL exceedance should occur "in accordance with its Reliability Coordinator's SOL methodology."

Requirement R8: Proposed Requirement R8 addresses the method for determining IROLs. As noted above, IROL issues were separated from the scope of Project 2015-09 for further technical consideration. Accordingly, proposed Requirement R8 uses language from the currently effective version of the standard. Proposed Requirement R8 provides:

> **R8**. Each Reliability Coordinator shall include in its SOL methodology:
>
> 8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).
>
> 8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL Tv.

Proposed Part 8.1 maps to Requirement R1, Part 1.3 of the currently effective version of the standard. Proposed Part 8.2 maps to Requirement R3, Part 3.7 of the currently effective version of the standard, although it replaces the word "violated" with "exceeding" to align the language with the rest of the standard and the TOP/IRO standards.

Requirement R9: Proposed Requirement R9 addresses the communication of the SOL methodology to those that are responsible for establishing SOLs and those that have a reliability need to know the manner in which SOLs are developed in that Reliability Coordinator Area. Proposed Requirement R9 provides:

> **R9.** Each Reliability Coordinator shall provide its SOL methodology to:
>
> 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.
>
> 9.2. Each of the following entities prior to the effective date of the SOL methodology:
>
> 9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Proposed Requirement R9 maps to Requirement R4 of FAC-011-3 but references the Planning Coordinator, not Planning Authority, to be consistent with the Functional Model and the TPL-001 standard. Requirement R9, Part 9.2.2 also uses the phrase "responsible for planning" instead of "models any portion of" to better distinguish those Planning Coordinators and Transmission Planners who have a reliability-related need for the methodology from those who simply acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area.

NERC is also proposing to retire the WECC Regional Difference currently in the FAC-011 standard. When the FAC-010 and FAC-011 standards were originally created in 2007, WECC had regional planning criteria in place, which was a combination of NERC Planning Standards and additional WECC Reliability Criteria. WECC added Regional Differences to these standards to include the additional planning criteria that were in effect at that time. The WECC Regional Difference essentially requires the evaluation of specified multiple Facility Contingencies when establishing SOLs. With the adoption of TPL-001-4, which resulted in significant changes to planning requirements, the WECC Regional Differences in FAC-010 and FAC-011 became redundant. WECC therefore proposed the elimination of the Regional Differences in the FAC-010 and FAC-011 standards.[44]

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[44] Additional information on the elimination of the WECC Regional Difference, including the rationale and process for WECC's proposal, is available here: https://www.wecc.org/Standards/Pages/WECC-0113.aspx.

Additionally, the modifications in proposed FAC-011-4 further obviate the need for the WECC Regional Difference. As discussed above, FAC-011-4 Requirement R5 provides Reliability Coordinators the responsibility to determine which, if any, multiple contingencies should be included in the determination of stability limits in OPAs and RTAs. The list in the Regional Difference is simply outdated and there is no reliability need for the Regional Difference to require specific multiple contingencies beyond those specified by the Reliability Coordinator.

6. Proposed Reliability Standard FAC-014-3

The purpose of proposed FAC-014-3 is to "ensure that [SOLs] used in the reliable operation of the [BES] are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies." Proposed FAC-014-3 improves upon the prior version of the standard by (1) clarifying functional entity responsibilities for establishing and communicating each type of SOL, and (2) enhancing coordination between planning and operations. The following is a description of each of the eight requirements of proposed FAC-014-3:

Requirements R1-R2 and R4 set out which functional entity is responsible for establishing SOLs and IROLs. Consistent with the currently effective version of the standard, Reliability Coordinators are responsible for establishing IROLs for its Reliability Coordinator Area (Requirement R1) and Transmission Operators are responsible for establishing SOLs for their portion of the Reliability Coordinator Area (Requirement R2), except that Reliability Coordinators are responsible for establishing stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area (Requirement R4).

As discussed in the SDT's Technical Rationale and mapping document for proposed FAC-014-3 (Exhibits C-2 and D-3, respectively), these requirements improve upon the currently effective version of the standard by: (1) removing ambiguous language that could be misread to make Reliability Coordinators responsible for ensuring the Transmission Operators established SOLs such that a failure of the Transmission Operator to establish SOLs in accordance with the SOL methodology could also result in a violation of FAC-014 for the Reliability Coordinator, and (2) removing ambiguous language from Requirement R2 that could be misinterpreted to require Transmission Operators to establish SOLs only if they have been specifically directed to by their Reliability Coordinator. The proposed language makes clear that each Transmission Operator is responsible for establishing SOLs for its portion of the Reliability Coordinator Area in accordance with the Reliability Coordinator's SOL methodology.

Proposed Requirement R4 also improves upon the currently effective version by requiring Reliability Coordinators to establish stability limits when the limit impacts more than one Transmission Operator in its footprint or adjacent footprints. This requirement ensures that the Reliability Coordinator, who has wide-area responsibility, establishes such stability limits and prevent any gaps in identification and monitoring of such stability limits. Transmission Operators are still required to establish stability limits for its system (including Generator Operator areas interconnected to its system) but Reliability Coordinators are now responsible for establishing a stability limit that impacts more than one Transmission Operator regardless of whether that stability limit was originally calculated by the Reliability Coordinator or one of the impacted Transmission Operators.

Where a stability limit impacts an adjacent Reliability Coordinator, the Reliability Coordinator establishing the stability limit shall use its own methodology and communicate the limit to the adjacent Reliability Coordinator(s) or Transmission Operators in accordance with other requirements: IRO-008-2, Requirement R5, IRO-014-3, Requirements R1.4 and R1.5, and proposed FAC-014-3, Requirement R5.3, as applicable. If different limits are established by each of the adjacent Reliability Coordinators or multiple Transmission Operators, the more conservative of the two limits should be the one used in operations in accordance with IRO-009-2, Requirement R3 or TOP-001-4, Requirement R18, respectively.

Proposed Requirements R3 and R5 address the communication of established SOLs. First, under Requirement R3, Transmission Operators must provide their SOLs to their Reliability Coordinators. The Transmission Operator should refer to the Reliability Coordinator's documented data specification necessary for performing OPAs, Real-time monitoring, and RTAs under IRO-010-2 for any guidance or requirements regarding the communication of SOLs.

Under Requirement R5, the Reliability Coordinator is then responsible for providing the SOLs (including the subset that are IROLs) to Planning Coordinators, Transmission Planners, and other Transmission Operators, as follows. At least once every 12 calendar months, the Reliability Coordinator must provide each Planning Coordinator and Transmission Planner within its Reliability Coordinator Area: (1) the SOLs for its Reliability Coordinator Area (Part 5.1), and (2) the following information for each established stability limit and IROL: the value of the stability limit or IROL, the Facilities that are critical to the derivation of the stability limit or the IROL, the associated IROL Tv for any IROL, the associated critical Contingency(ies), a description of system conditions associated with the stability limit or IROL, and the type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability) (Part 5.2). The objective of these requirement parts is to provide the planning entities the relevant information necessary for performing their annual assessments.

Additionally, in an agreed upon timeframe, the Reliability Coordinator must provide each impacted Transmission Operator within its Reliability Coordinator Area: (1) the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1 for inclusion in the Transmission Operator's OPAs, Real-time monitoring, and RTAs (Part 5.3), and (2) the information identified in Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information (Part 5.4). The additional information covered under Requirement R5 Part 5.4 helps ensure that the Transmission Operator has the necessary information for performing OPAs and RTAs.

The Reliability Coordinator must also provide each requesting Transmission Operator within its Reliability Coordinator Area SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule (Requirement R5 Part 5.5). A Transmission Operator may want such information, for example, for deriving a new SOL that may impact adjacent Transmission Operators.

Last, consistent with the Commission's directive in Order No. 777, the Reliability Coordinator must provide each impacted Generator Owner or Transmission Owner within its Reliability Coordinator Area with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies, at least once every twelve calendar months (Requirement R5 Part 5.6). As discussed above, this information would help asset owners understand which of their facilities are critical to maintaining reliability and require increased protection under the CIP standards.

The proposed Requirement R5 addresses both the content and the frequency at which the information is provided. It also complements existing requirements that provide for communication of SOLs and SOL-related information (e.g., TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. Transmission Operator-to-Transmission Operator communication is addressed in TOP-003-3 and Reliability Coordinator-to-Reliability Coordinator communication is addressed in IRO-014-2.

Proposed Requirements R6-R8 further address coordination between planning and operations. Requirement R6 is designed to align the Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models. Analysis of these models determine System needs, potential future transmission expansion, and other CAPs for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 aligns the analysis input assumptions and System performance criteria used in planning and operating the BES by requiring each Planning Coordinator and Transmission Planner to "implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology."

Requirement R6 thus provides a mechanism for the coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria in planning models to those established in accordance with the Reliability Coordinator's SOL methodology. As the analysis of planning models determines which Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the Reliability Coordinator's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The SDT recognized, however, that there are instances where it may be appropriate for planning models to have less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in accordance with the SOL methodology. For example, the planning entities may need to model for an upgrade to its system that increases the Facility Rating (typically, the thermal limit) of the equipment in question. So long as the operators are aware of this exception, planning and operations will continue to be aligned. Accordingly, proposed Requirement R6 provides that the Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits, and stability criteria, if it provides a technical rationale to each affected Transmission Planner, Transmission Operator, and Reliability Coordinator. Similarly, the Transmission Planner may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator, and Reliability Coordinator.

Proposed Requirement R7 also enhances coordination between planning and operations by requiring Planning Coordinators and Transmission Planners to communicate the following information to each impacted Transmission Operator and Reliability Coordinator annually:

- The CAP developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as RAS, UVLS, or any Operating Procedures) (Part 7.1).
- The type of instability addressed by the CAP (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping) (7.2).
- The associated stability criteria violation requiring the CAP (e.g. violation of transient voltage response criteria or damping rate criteria) (7.3).
- The planning event Contingency(ies) associated with the identified instability requiring the CAP (7.3).

- The System conditions and Facilities associated with the identified instability requiring the CAP (7.5).[45]

Providing this information would help inform Reliability Coordinators and Transmission Operators when establishing SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure or RAS. If the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Currently effective FAC-014-2, Requirement R6 requires the sharing of similar, though less detailed, information.

Proposed Requirement R8 requires Planning Coordinators and Transmission Planners to, on an annual basis, provide each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. This requirement helps ensure that Transmission Owners and Generation Owners have the appropriate details regarding potential instability, Cascading, or uncontrolled separation identified in their Planning Assessment for the Near-Term Transmission Planning Horizon. The owners can then use this information to identify the Facilities that, as required by other Reliability Standards (e.g., CIP-002, CIP-014, FAC-003), require some level of protection, hardening, or increased vegetation

[45] Requirement R7 references CAPs, in part, to clarify that the requirement does not include the communication of information related to Extreme Events. The SDT concluded that including Extreme Events would dilute the information provided under this requirement and may be an undue burden to planning entities. The use of CAPs also eliminates requirements to provide information on simple out of step generator protection (properly) taking a unit offline.

management. This requirement addresses the FERC Order No. 777 directive to address the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement R5 Part 5.6, provides annual notifications to Facility owners from both operating and planning entities.

7. Proposed Reliability Standard IRO-008-3

As noted above, NERC is proposing changes to the IRO-008 standard to align it with the proposed changes in FAC-011-4. The IRO-008 standard requires Reliability Coordinators to perform analyses and assessments (e.g., OPA) to prevent instability, uncontrolled separation, or Cascading. The most substantial revision was the addition of new Requirement R7. Proposed Requirement R7 provides the link to proposed FAC-011-4, Requirement R6 by requiring a Reliability Coordinator to use its SOL methodology when determining SOL exceedances for RTAs, Real-time monitoring, and OPAs. NERC is also proposing modifications to Requirements R5 and R6 to require the notifications regarding SOL or IROL exceedances to be done according to the risk-based approach in the Reliability Coordinator's SOL methodology required in proposed FAC-011-4, Requirement R7.

8. Proposed Reliability Standard TOP-001-6

Similarly, NERC is proposing changes to the TOP-001 standard to align it with proposed FAC-011-4. The TOP-001 standard includes requirements related to Transmission Operators' obligations to conduct Real-time monitoring and RTAs, among other things. The most substantial revision was the addition of new Requirement R25. Proposed Requirement R25 provides the link to proposed FAC-011-4, Requirement R6 by requiring Transmission Operators to use its Reliability Coordinator's SOL methodology when determining SOL exceedances for RTAs, Real-time monitoring, and OPAs. NERC is also proposing modifications to Requirement R15 to require notifications regarding SOL exceedances to be done according to the risk-based approach in the Reliability Coordinator's SOL methodology required in proposed FAC-011-4, Requirement R7.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the implementation plan attached to this petition as **Exhibit B**. The proposed implementation plan provides that the proposed Reliability Standards, NERC Glossary terms, and retirements would become effective on the first day of the first calendar quarter that is 24 months after FERC approval. The currently effective versions of the standards would be retired immediately prior to the effective date of the revised Reliability Standards. This implementation timeline reflects consideration that entities will need to establish and develop new procedures and processes to meet the proposed requirements. Many entities may also need to make certain enhancements to systems, such as their energy management systems or Real-time Contingency Analysis tools, to help them comply with the new requirements, particularly those related to identifying SOL exceedances.

The implementation plan also specifies that unless otherwise specified therein, the elements of the implementation plans for FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2. This provision helps ensure that certain timelines in those prior implementation plans remain unchanged. The implementation plan also includes additional implementation provisions to address revisions in proposed Reliability Standards PRC-002-3, PRC-023-5, PRC-026-2, and FAC-014-3 that require new or different actions by the same or different entities than the prior version of the Reliability Standards required. These additional provisions largely address when entities must comply with periodic requirements after the effective date of the modified version of the standard.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, IRO-008-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, and the associated elements, as shown in **Exhibit A;**
- the retirement of currently effective Reliability Standard FAC-010-3;
- the proposed definitions for the terms System Operating Limit and System Voltage Limit to be incorporated into the NERC Glossary; and
- the implementation plan included in **Exhibit B**.

Respectfully submitted,

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

FAC-011-4 (Clean and Redline to Last Approved)

A. Introduction

Title: **System Operating Limits Methodology for the Operations Horizon**

Number: FAC-011-4

Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

1.1. Functional Entities:

4.1.1. Reliability Coordinator

Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology.

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology, that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the minimum allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1 IROL exceedances;

7.1.2 SOL exceedances of stability limits;

7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.
R4.	The Reliability Coordinator failed to incorporate one of	The Reliability Coordinator failed to incorporate two of	The Reliability Coordinator failed to incorporate three of	The Reliability Coordinator failed to incorporate four or

Requirement	Lower	Moderate	High	Severe
	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	more of the Parts of Requirement R4 into its SOL methodology.
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be

Requirement	Lower	Moderate	High	Severe
		include one of the Parts 7.2.1 through 7.2.2.	include one of the Parts 7.1.1 through 7.1.5.	communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9,

Requirement	Lower	Moderate	High	Severe
	Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	

4	May 13, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2015-09

A. Introduction

Title: **System Operating Limits Methodology for the Operations Horizon**

Number: FAC-011-4~~3~~

Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

1.1. Functional Entities:

4.1.1. Reliability Coordinator

Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. ~~The~~ Each Reliability Coordinator shall have a documented methodology for ~~use in~~establishing ~~developing~~ SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area. ~~This SOL Methodology shall:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.0.** Be applicable for developing SOLs used in the operations horizon.~~

~~**2.0.** State that SOLs shall not exceed associated Facility Ratings.~~

~~**3.0.** Include a description of how to identify the subset of SOLs that qualify as IROLs.~~

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its ~~The Reliability Coordinator's~~ SOL ~~M~~methodology ~~shall address all of the items listed in Requirement 1 through Requirement 3.~~

R2. ~~The~~ Each Reliability Coordinator ~~'s~~shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings ~~shall include a requirement that SOLs provide BES performance consistent with the following:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**4.0.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.~~

~~**2.1.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

~~**0.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.~~

~~**0.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

~~**0.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.~~

~~**8.0.** In determining the system's response to a single Contingency, the following shall be acceptable:~~

~~**0.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**0.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**0.** System reconfiguration through manual or automatic control or protection actions.~~

~~**12.0.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its ~~The Reliability Coordinator shall have evidence it issued its~~ SOL ~~M~~methodology, that addresses the items listed in Requirement R2~~and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.~~

~~R4.~~R3. ~~The~~ Each Reliability Coordinator~~'s~~ shall include in its SOL methodology ~~method~~the method~~ology~~ for Transmission Operators to determin~~e~~ing the System Voltage Limits to be used in operations. The method shall: ~~SOLs, shall include, as a minimum, a description of the following, along with any reliability~~

~~[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~margins applied for each:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~4.1.~~3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;~~Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~4.2.~~3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;~~Selection of applicable Contingencies~~

~~4.3.~~3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;~~A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.~~

~~0. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~4.5.~~3.4. Identify the minimum allowable System Voltage Limit;~~Level of detail of system models used to determine SOLs.~~

~~4.6.~~3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection~~Allowed uses of Remedial Action Schemes~~.

~~13.0. Anticipated transmission system configuration, generation dispatch and Load level~~

~~14.0. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.~~

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

~~R5.~~**R4.** ~~The~~ Each Reliability Coordinator shall include in ~~issue~~ its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:~~

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:~~Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.~~

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

~~5.1.~~4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its~~Each Planning Authority and Transmission Planner that models any~~ portion of ~~the Reliability Coordinator's Reliability Coordinator Area~~the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one~~Each~~ Transmission Operator in its Reliability Coordinator Area or other ~~that operates in the~~ Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1 IROL exceedances;

7.1.2 SOL exceedances of stability limits;

7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

~~**M15.**~~

~~M16.~~M1. ~~The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~M17.~~M1. ~~The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.~~

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1.	N/A~~Not applicable.~~	N/A~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~	N/A~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~did not have a documented SOL ~~M~~methodology for ~~use in developing~~ establishing SOLs within its Reliability Coordinator Area~~, but it does not address R1.1~~. ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.~~
R2.	N/A~~The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~	N/A~~Not applicable.~~	The Reliability ~~Coordinator's~~Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators	The Reliability Coordinator~~'s~~ did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.~~does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single~~

Requirement	Lower	Moderate	High	Severe
			in its Reliability Coordinator Area.~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~	~~contingencies. (R2.1 through R2.4)~~
R3.	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate two of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate four or more of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~is missing a description of four or more of the following: R3.1 through R3.7~~.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~

Requirement	Lower	Moderate	High	Severe
	~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to30 days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of the required entities more than30 calendar days after the effectiveness of the change.~~
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining

Requirement	Lower	Moderate	High	Severe
		how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.2.1 through 7.2.2.	how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.1.1 through 7.1.5.	how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.

Requirement	Lower	Moderate	High	Severe
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to

Requirement	Lower	Moderate	High	Severe
				a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

~~1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:~~

~~1.3. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:~~

~~1.3.0 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.~~

~~1.3.0 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7~~

~~1.3.0 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.~~

~~1.3.0 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.~~

~~1.3.0 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.~~

~~1.3.0 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.~~

~~1.3.0 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.~~

~~1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:~~

~~1.3.0 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.~~

~~1.3.0 Cascading does not occur.~~

~~**1.3.1** Uncontrolled separation of the system does not occur.~~

~~**1.3.1** The system demonstrates transient, dynamic and voltage stability.~~

~~**1.3.1** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~**1.3.1** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~**1.3.1** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~**1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~**1.3.1** Cascading does not occur.~~

~~**1.3.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

~~None.~~Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	

4	May 13, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2015-09

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-2

FAC-014-3 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL methodology”).
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective

			limiting Facility Ratings, System Voltage Limits or stability criteria	Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission

			Owner, and Generation Owner, but failed to provide them annually.	Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3	May 13, 2021	Adopted by Board of Trustees	Revised under Project 2015-09

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-~~2~~3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable ~~planning and~~ operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability**
   - 4.1. **Functional Entities**
     - **4.1.1.** Planning Coordinator
     - **4.1.2.** Reliability Coordinator
     - **4.1.3.** Transmission Operator
     - **4.1.4.** Transmission Planner
5. **Effective Date:** ~~April 29, 2009~~See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. ~~The~~ Each Reliability Coordinator shall establish ~~ensure that SOLs, including~~ Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*~~for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology~~

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

R2. ~~The~~ Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the ~~(as directed by its~~ Reliability Coordinator~~)~~ Area in accordance with ~~for~~ its ~~portion of the~~ Reliability Coordinator's ~~Area that are consistent with its Reliability Coordinator's~~ SOL ~~M~~methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.~~The Reliability~~

~~Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

R3. ~~The~~ Each ~~Planning Authority~~Transmission Operator shall provide its ~~establish~~ SOLs~~,~~ to its Reliability ~~Coordinator~~ Coordinator ~~including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.~~

R4. ~~The Transmission Planner~~Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with ~~SOLs, including IROLs, for its Transmission Planning Area that are consistent with~~ its ~~Planning Authority's~~ SOL ~~M~~methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~M1.~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

~~R3.~~R5. Each~~The~~ Reliability Coordinator~~, Planning Authority, and Transmission Planner~~ shall ~~each~~ provide ~~its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows~~: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 ~~The Reliability~~Each Planning Coordinator and each Transmission Planner within ~~shall provide~~ its ~~SOLs (including the subset of SOLs that are IROLs) to adjacent~~ Reliability Coordinator ~~s~~ Area,and ~~Reliability Coordinators who indicate a reliability-related need for those limits, and to~~ the SOLs ~~Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within~~for its Reliability Coordinator Area~~.~~ ~~(including~~including the subset of SOLs that are ~~For each~~ IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*~~, the Reliability Coordinator shall provide the following supporting information:~~

5.2 ~~Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.~~

~~The value of the IROL and its associated T_v.~~

~~The associated Contingency(ies).~~

~~The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).~~

Each impacted Planning Coordinator and each impacted~~The~~ Transmission ~~Operator~~ Planner ~~shall provide any SOLs it developed to~~within its Reliability Coordinator Area,~~and to~~ the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*~~Transmission Service Providers that share its portion of the Reliability Coordinator Area.~~

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within~~The Planning Authority shall provide~~ its ~~SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and~~ Reliability Coordinator Area~~s~~, the value of the stability limits —established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*~~that work within its Planning Authority Area.~~

5.4 Each impacted~~The~~ Transmission ~~Planner~~ Operator ~~shall provide its SOLs (including the subset of SOLs that are IROLs) to~~within its ~~Planning Authority,~~ Reliability Coordinator~~s~~ Area, the information identified in —Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*~~Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

~~M2.~~M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

~~R4.~~R6. ~~The~~ Each Planning ~~Authority~~ Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

- The Planning Coordinator may ~~Authority~~ use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.~~shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~
- ~~If t~~The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and~~Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

~~**M3.**~~**M8.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

~~C. Measures~~

~~M4.M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~M5.M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~M6.M1. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.~~

~~G.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:~~Compliance Monitoring Responsibility~~

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~Regional Reliability Organization~~

1.2. Evidence Retention:~~Compliance Monitoring Period and Reset Time Frame~~

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~1.5.~~1.3. Compliance Monitoring and Enforcement Program~~Data Retention~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**1.6.0** SOL Methodology(ies)~~

~~**1.6.0** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**1.6.0** Evidence that SOLs were distributed~~

~~**1.6.0** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**1.6.0** Distribution schedules provided by entities that requested SOLs~~

Violation Severity Levels:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	N/A~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	N/A~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology").~~There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~
R2.	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.~~The Transmission Operator has established SOLs for its portion of the Reliability~~

				~~Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~
R3.	N/A~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	N/A~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.~~There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~
R4.	N/A~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	N/A~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	N/A~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.~~The~~

				~~Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~
R6.	N/A~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~	N/A~~Not applicable.~~	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings,

			limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~	System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not

	contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

~~H.~~D. Regional Variances

None.

~~I.~~E. Interpretations

None.

~~J.~~F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3	May 13, 2021	Adopted by Board of Trustees	Revised under Project 2015-09

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-3

FAC-003-5 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[1] state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

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[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[2] state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system <u>performance result or outcome</u>?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that <u>reduces a stated risk</u> to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have <u>what capability</u>, to achieve what particular result or*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

> *outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[7]

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

M2. [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this Reliability Standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

(as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and encroachment into the MVCD as identified in FAC-003-5-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.Reserved for future use				

R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.

R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	May 13, 2021	Adopted by Board of Trustees	Revisions under Project 2015-09

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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12 The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

13 Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

14 The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

[+] Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

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[15] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[16] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[17] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1:
R1 is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines R1 requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirements R1 states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable

Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

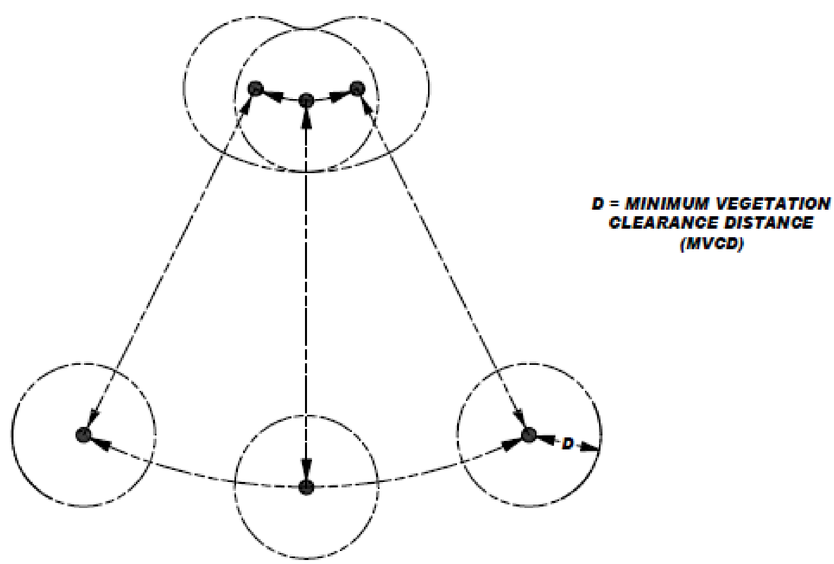

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner’s vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5~~4~~

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[1]~~,~~ state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[2]~~,~~ state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. **Effective Date:** See Implementation Plan

6. **Background:** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

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[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for R~~r~~eliability S~~s~~tandards development recognizes that each requirement in a NERC R~~r~~eliability S~~s~~tandard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability S~~s~~tandards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a R~~r~~eliability S~~s~~tandard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s),~~ which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all

Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[7]~~;~~

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:~~

~~**2.1.** An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]~~

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

~~[9] *See footnote 4.*~~

~~[10] *See footnote 5.*~~

~~[11] *See footnote 6.*~~

~~**2.2.** An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]~~

~~**2.3.** An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]~~

~~**2.4.** An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

M2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)~~

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

~~12. *Id.*~~

~~*13. Id.*~~

~~R7.~~R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

~~R8.~~R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

~~R9.~~R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

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[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, ~~R2,~~ R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote ~~2~~4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~as an element of~~

~~an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 ~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-~~4~~5-Table 2 was observed in real time	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 ~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following:

			absent a Sustained Outage.	• *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.Reserved for future use			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ ~~*A fall-in from inside the active transmission line ROW*~~ ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~

				~~A grow-in~~
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned

				vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	May 13, 2021	Adopted by Board of Trustees	Revisions under Project 2015-09

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

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15 The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

16 Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

17 The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV~~-~~, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~, to become elements of an IROL or Major WECC Transfer Path~~ in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path~~ may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an ~~IROL~~ identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:

The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the ~~S~~standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:

In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1~~ and R2~~:

R1 ~~and R2 are~~is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines~~. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both~~ R1 ~~and R2 ~~requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer ~~in the Applicability section 4.2 and 4.3~~Path~~~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~. ~~R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separationpursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths.~~

~~The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separationthat is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Pathshave not been identified as such. Applicable lines that are not elements of IROLs or Major WECC Transfer Pathshave not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.~~

Requirements R1 ~~and R2~~ states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 ~~and R2~~ are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

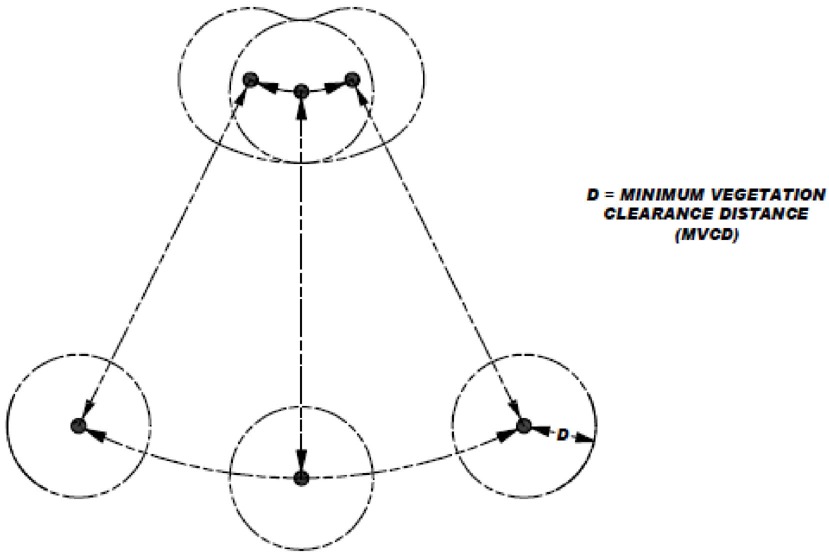

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1~~ and R2~~:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner’s vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-4

TOP-001-6 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Balancing Authority
   4.1.2. Transmission Operator
   4.1.3. Generator Operator
   4.1.4. Distribution Provider
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two

hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator’s SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	May 13, 2021	Adopted by the Board of Trustees	Revised under Project 2015-09

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-~~5~~6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Generator Operator
     - **4.1.4.** Distribution Provider
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated

action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 ~~for three calendar years~~~~rolling~~for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

~~1.4.~~1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	May 13, 2021	Adopted by the Board of Trustees	Revised under Project 2015-09

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-5

IRO-008-3 (Clean and Redline to Last Approved)

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments

2. **Number:** IRO-008-3

3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.

4. **Applicability**

   4.1. Reliability Coordinator.

5. **Proposed Effective Date:**

   See Implementation Plan.

6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, R6, and R7 and Measures M1 through M3, M5, M6, and M7 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan,

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit	when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Area.		(IROL) exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan	Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit	Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability	when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			when the when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	(SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments

2. **Number:** IRO-008-~~2~~3

3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.

4. **Applicability**

   4.1. Reliability Coordinator.

5. **Proposed Effective Date:**

   See Implementation Plan.

6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Reliability Operating ~~Reliability~~ Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, ~~and~~ R6, and R7 and Measures M1 through M3, M5, ~~and~~ M6, and M7 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating ~~Reliability~~ Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authorities.
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time	High	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period,	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations		period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL)	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection	Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			exceedance within its Wide Area.		Reliability Operating Limit (IROL) exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as	Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three	impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			indicated in its Operating Plan when the when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-6

PRC-002-3 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised under Project 2015-09

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-3 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this

determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing

filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-3~~2~~

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator**~~

~~**4.1.3** Western Interconnection – Reliability Coordinator~~

~~**4.1.4** Quebec Interconnection – Planning Coordinator or Reliability Coordinator~~

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~2~~3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~2~~3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner,~~ Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised under Project 2015-09

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC | ~~RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator~~ and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-~~2~~3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners

across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of

selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a ~~-~~10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-~~2~~ 3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-~~2~~ 3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-~~2~~ 3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-~~2~~ 3 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:
Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those

thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the

contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-~~2~~ 3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be

expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its

initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-7

PRC-023-5 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-5

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

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[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-5 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-5, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	Revisions under Project 2015-09

PRC-023-5 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-5 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-54
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: ~~:~~ See Implementation ~~**Plan for (?)**~~~~See Implementation Plan for the Revised Definition of "Remedial Action Scheme"~~.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~4~~5 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~4~~5, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	Revisions under Project 2015-09

PRC-023-45 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-45 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

~~**B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

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[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-8

PRC-026-2 (Clean and Redline to Last Approved)

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

4.1.2 Planning Coordinator.

4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

4.2.1 Generators.

4.2.2 Transformers.

4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates: See Implementation Plan

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event..
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	May 13, 2021	Adopted by NERC Board of Trustees	Revised under Project 2015-09

PRC-026-2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., “load-responsive”) including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-2 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-2 – Attachment B.

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[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay’s susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1)
$$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

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[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

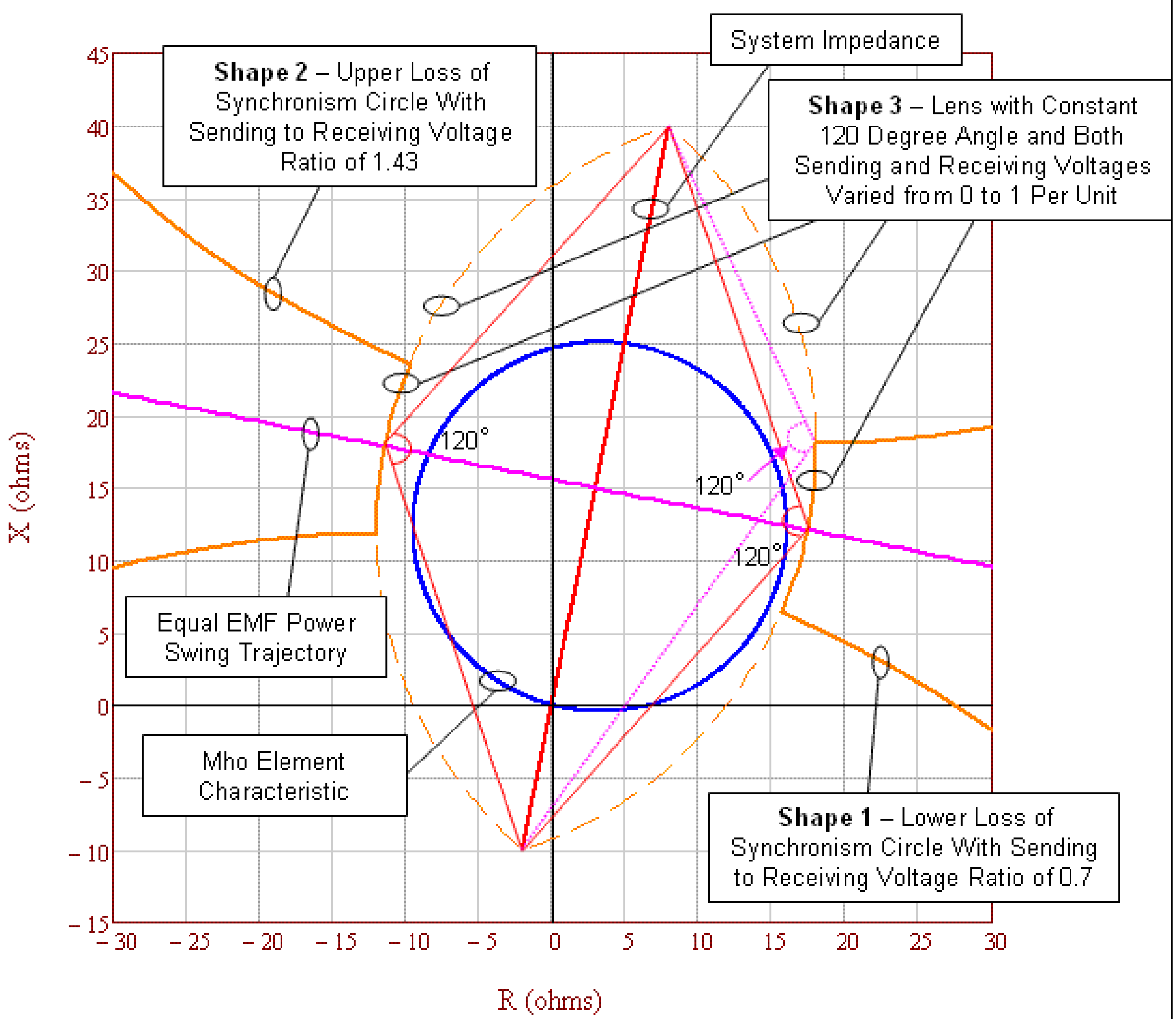


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-2 – Attachment B, Criterion A, No. 1.

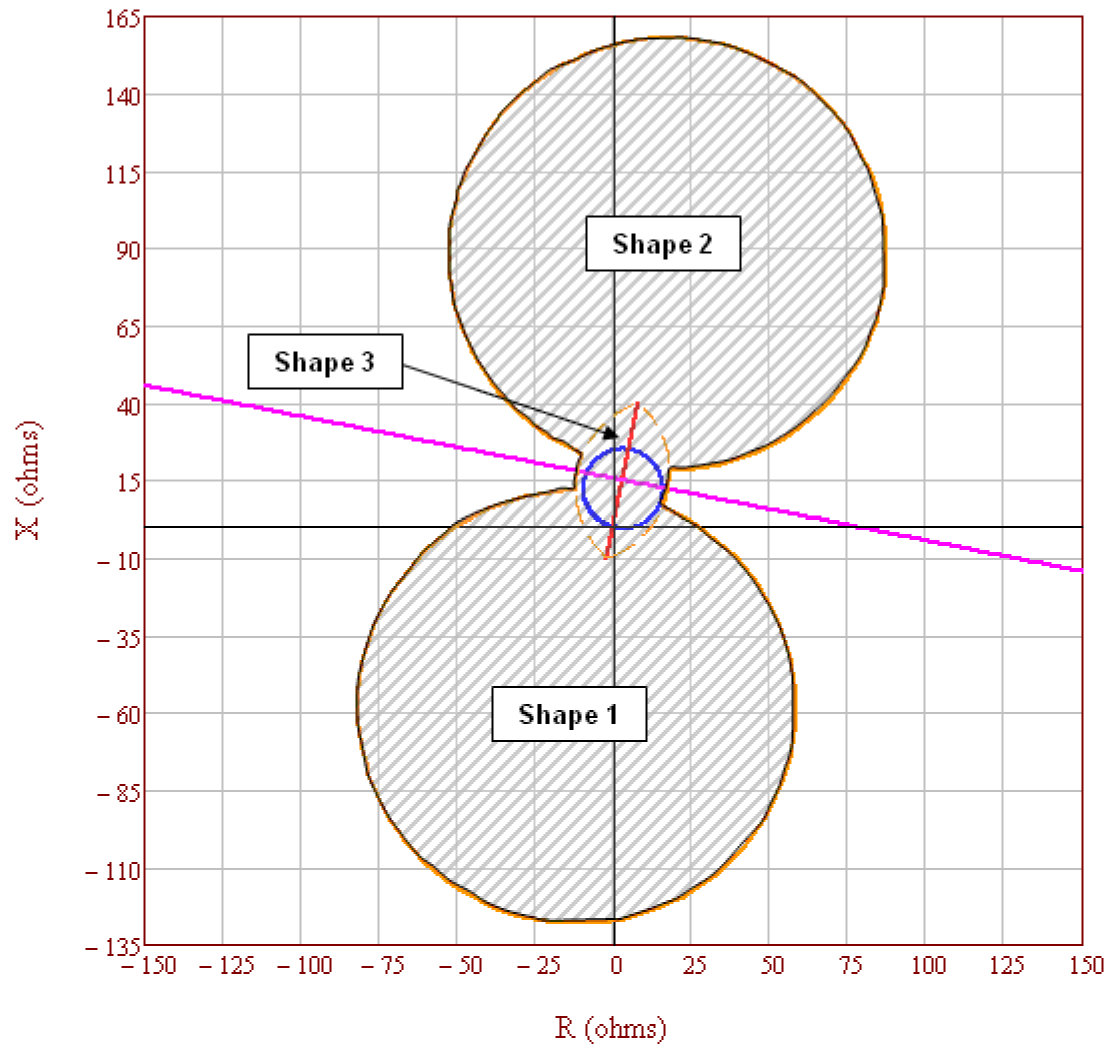


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

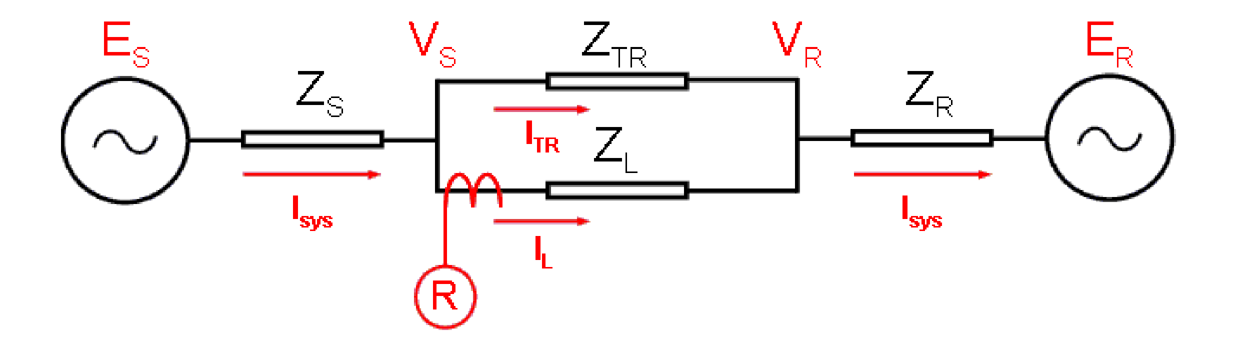


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

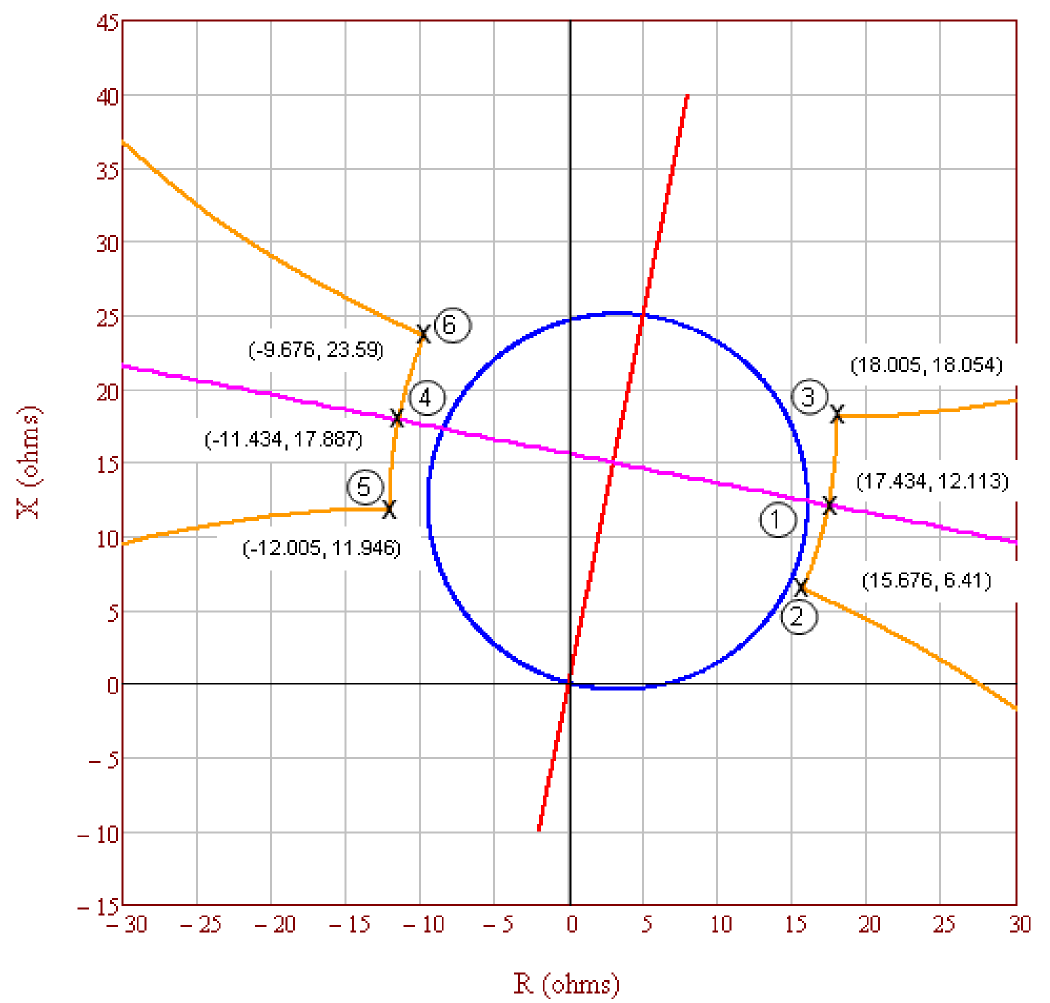


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10+j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2+j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

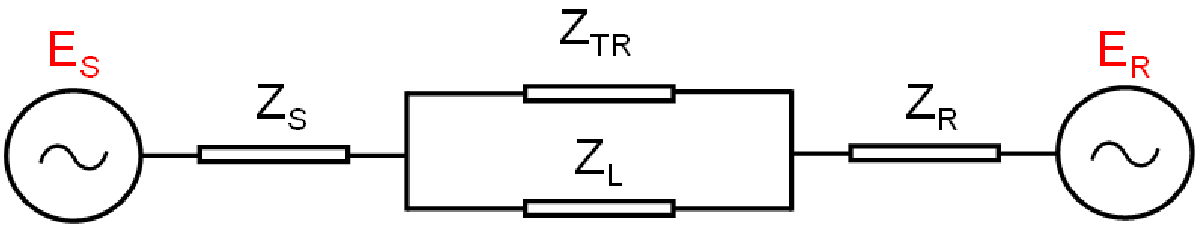
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1° \, A]$
	$V_S = 95{,}756\angle -106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle -106.1° \, V}{4{,}511\angle 131.1° \, A}$
	$Z_{L-Relay} = -11.434 + j17.887 \, \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 240° \, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240° \, V$		
Eq. (39)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \, \Omega$	$Z_L = 4 + j20 \, \Omega$	$Z_R = 4 + j20 \, \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \, \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

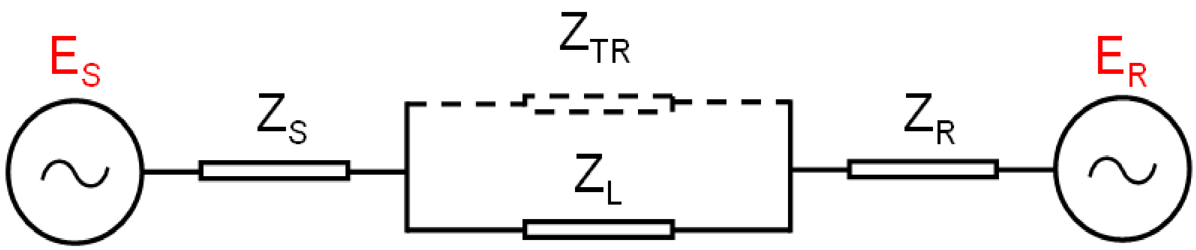
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle - 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

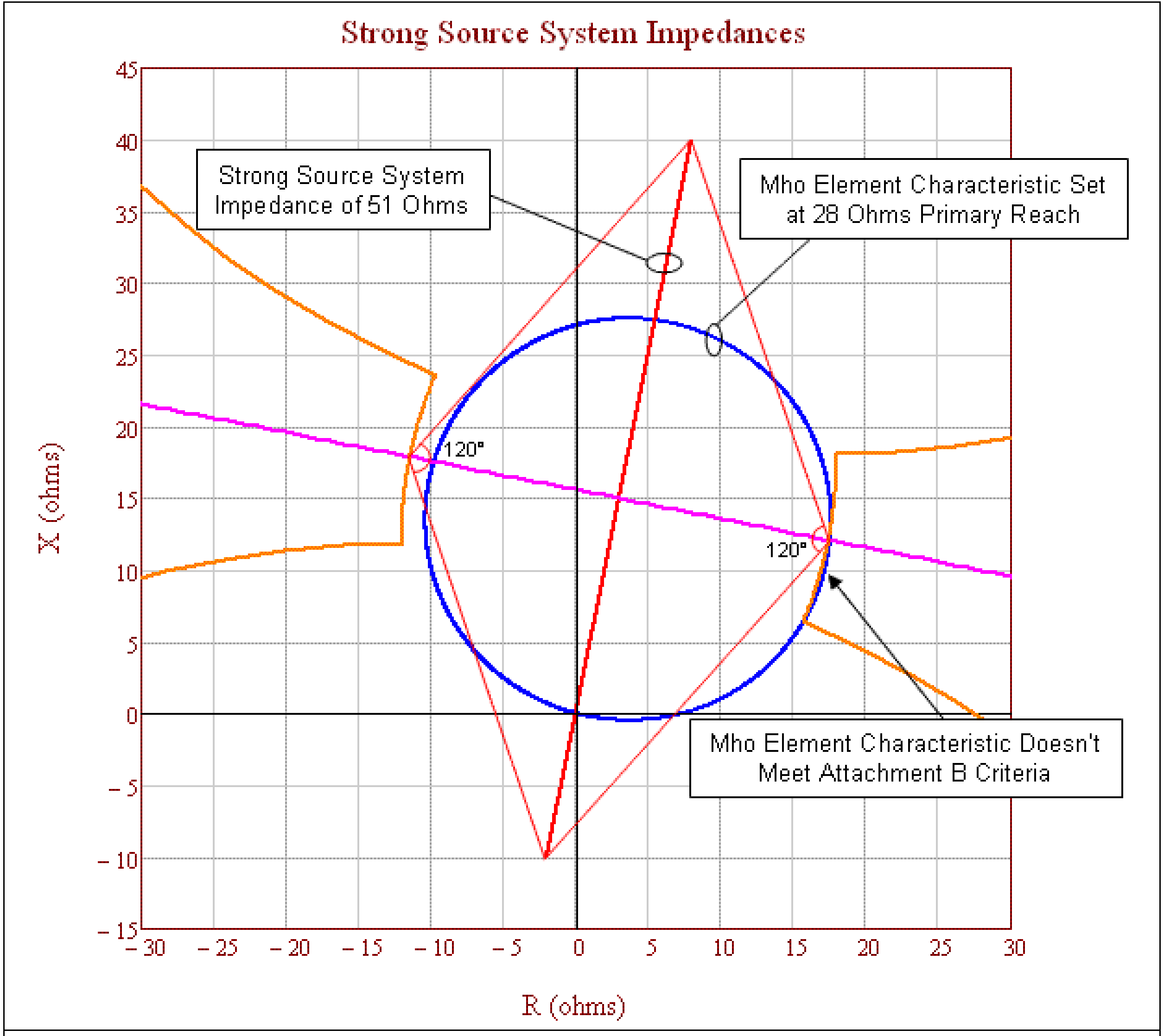


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

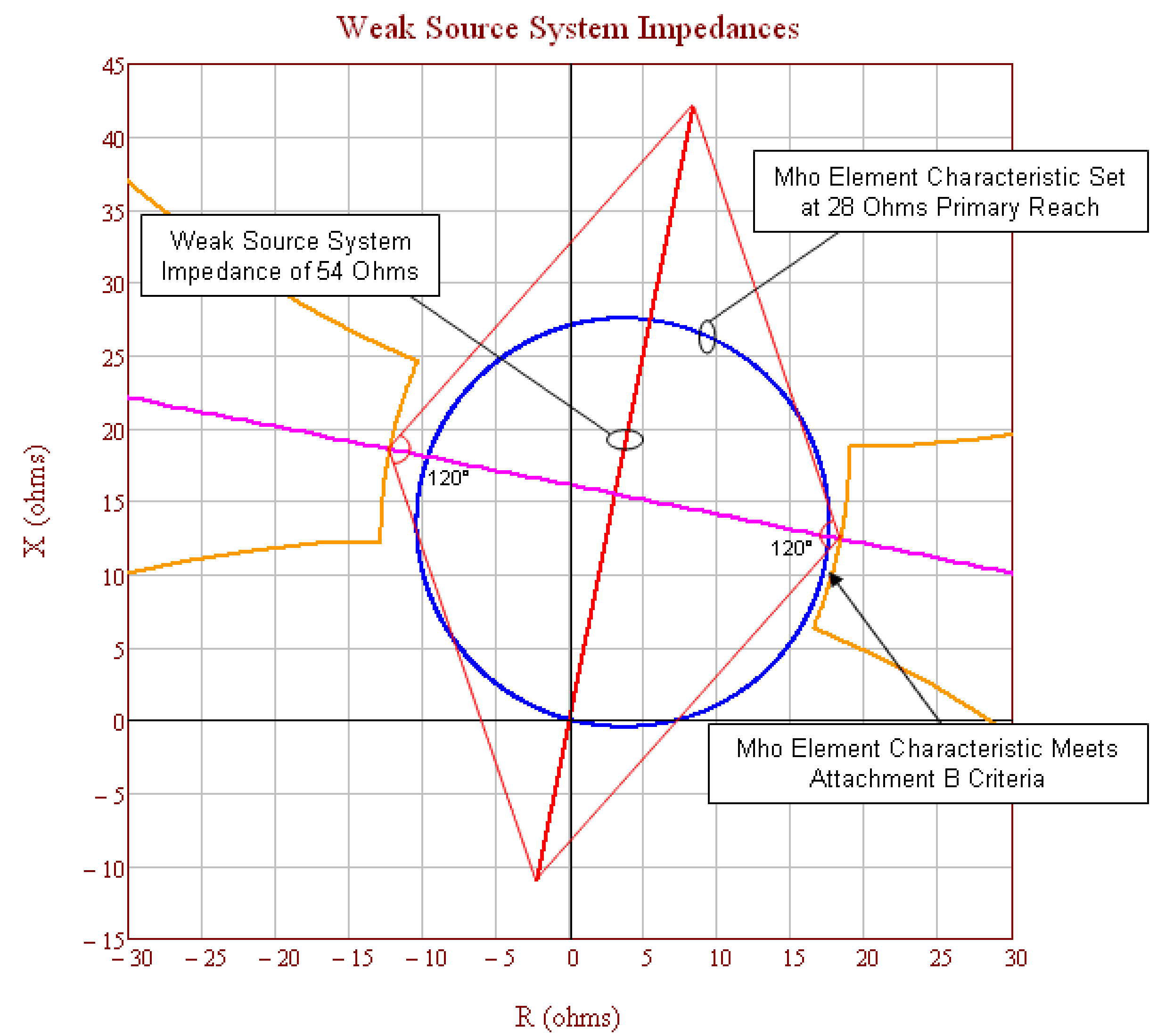


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

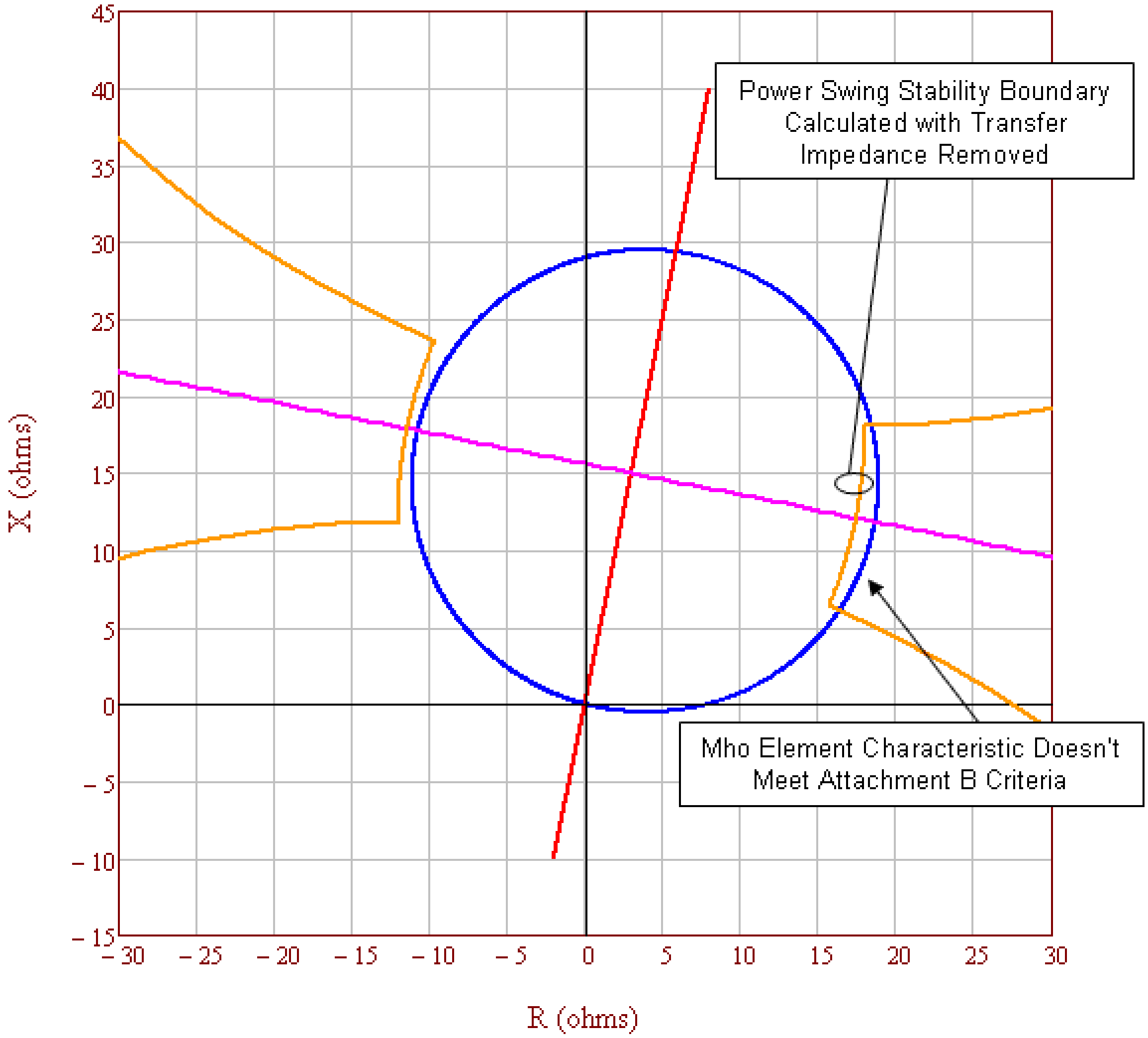


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)

Eq. (55)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

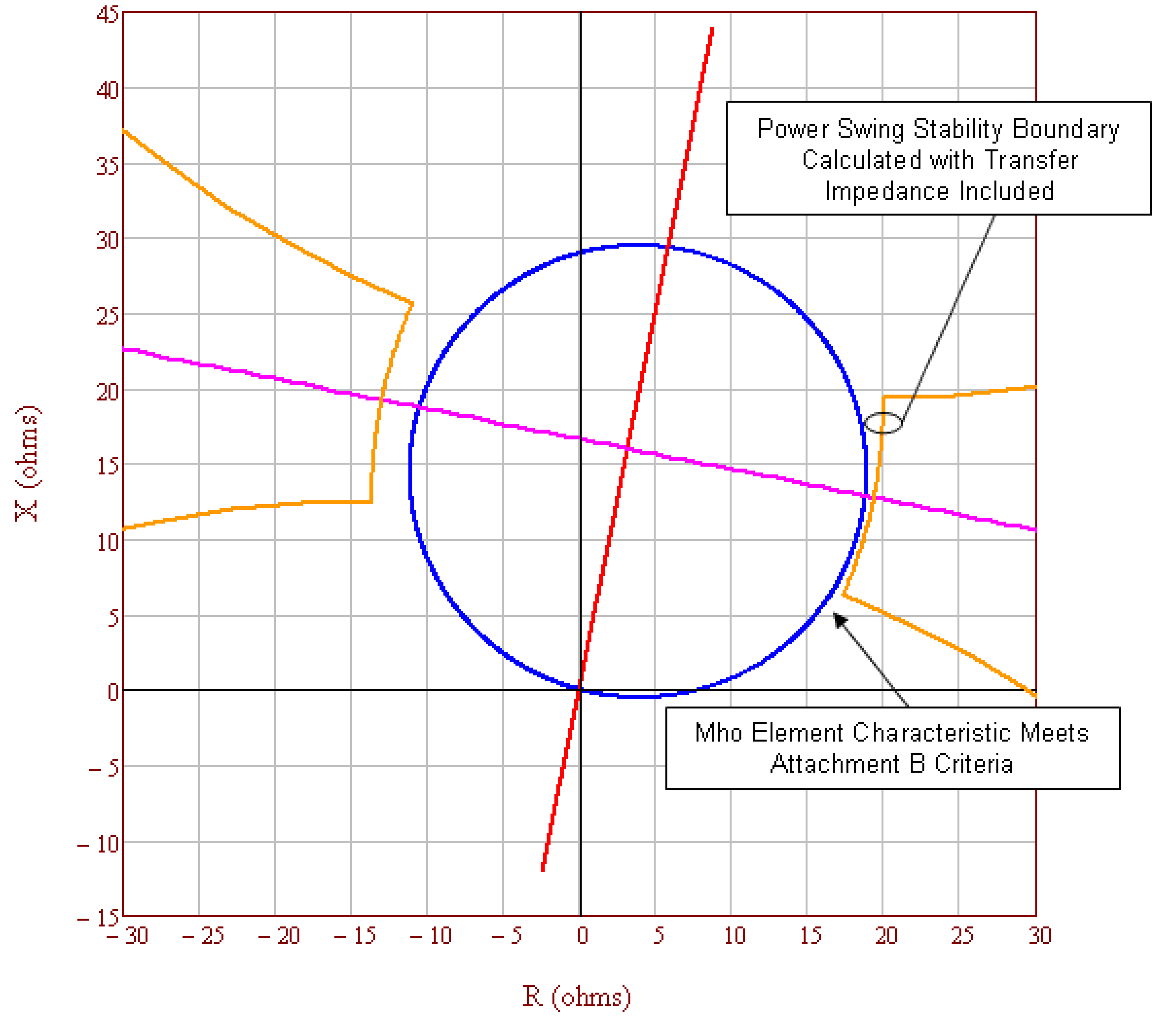


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

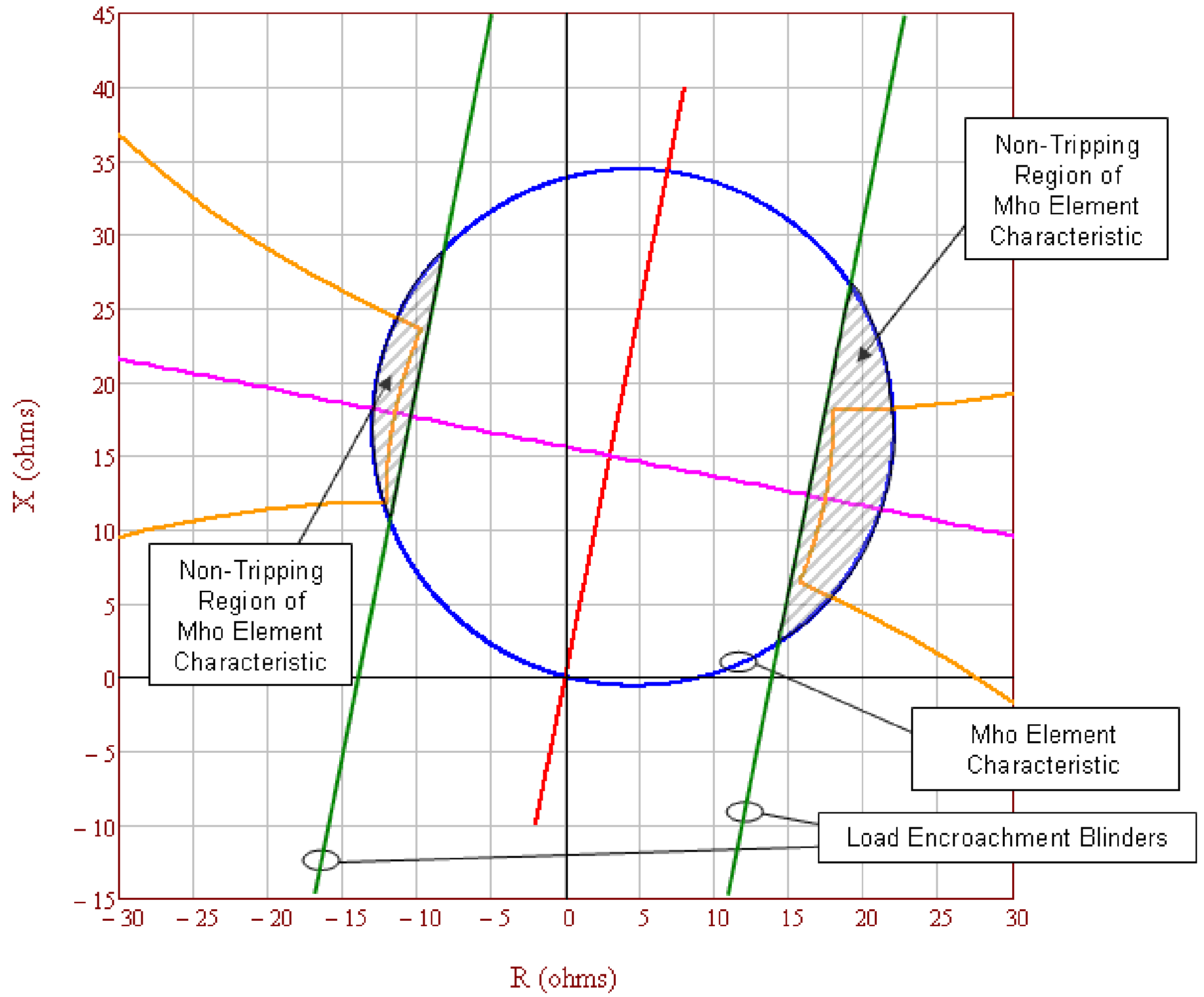


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-2– Attachment B, Criterion A.

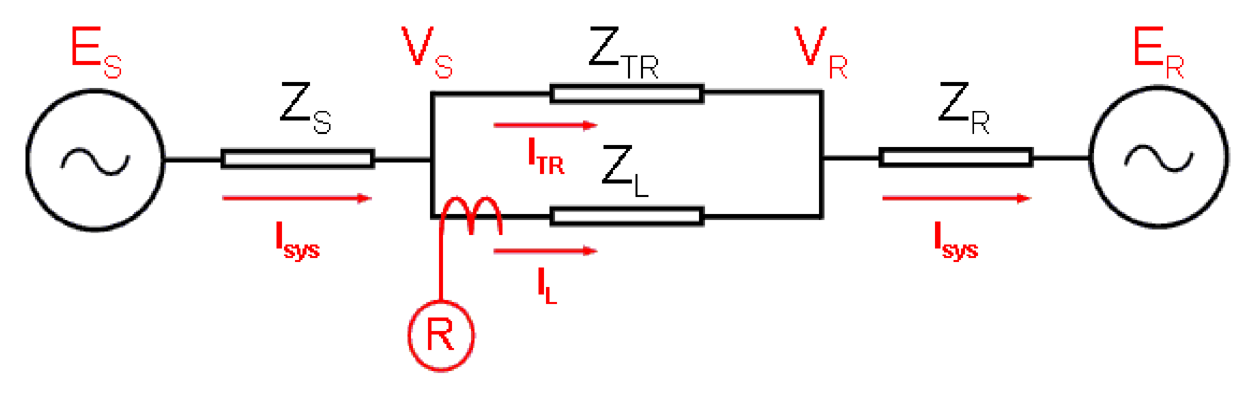


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

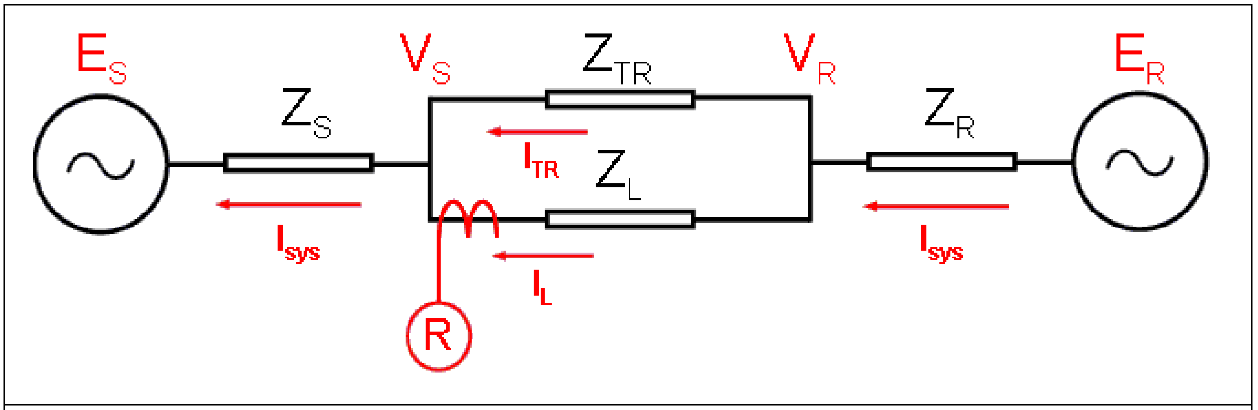


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

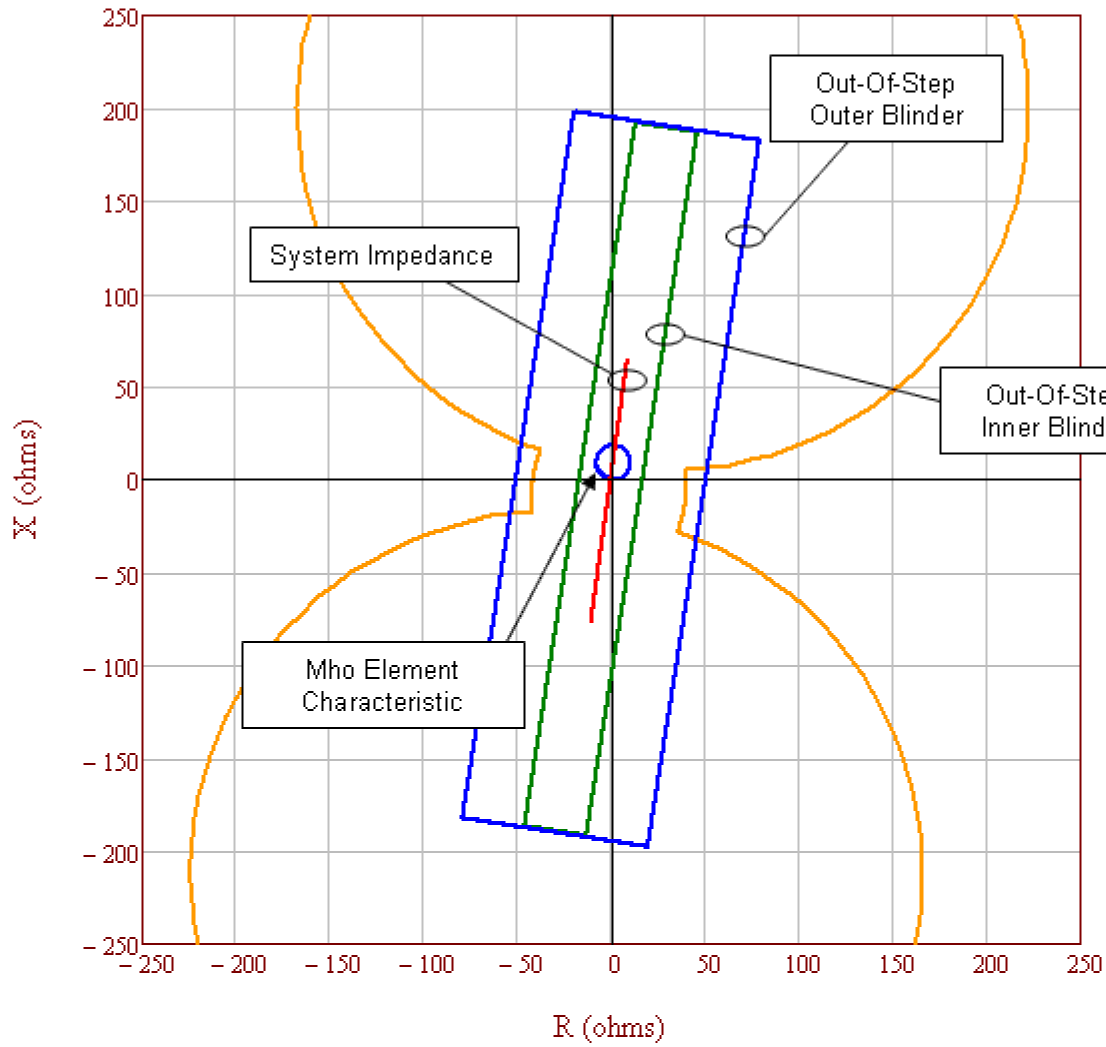


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

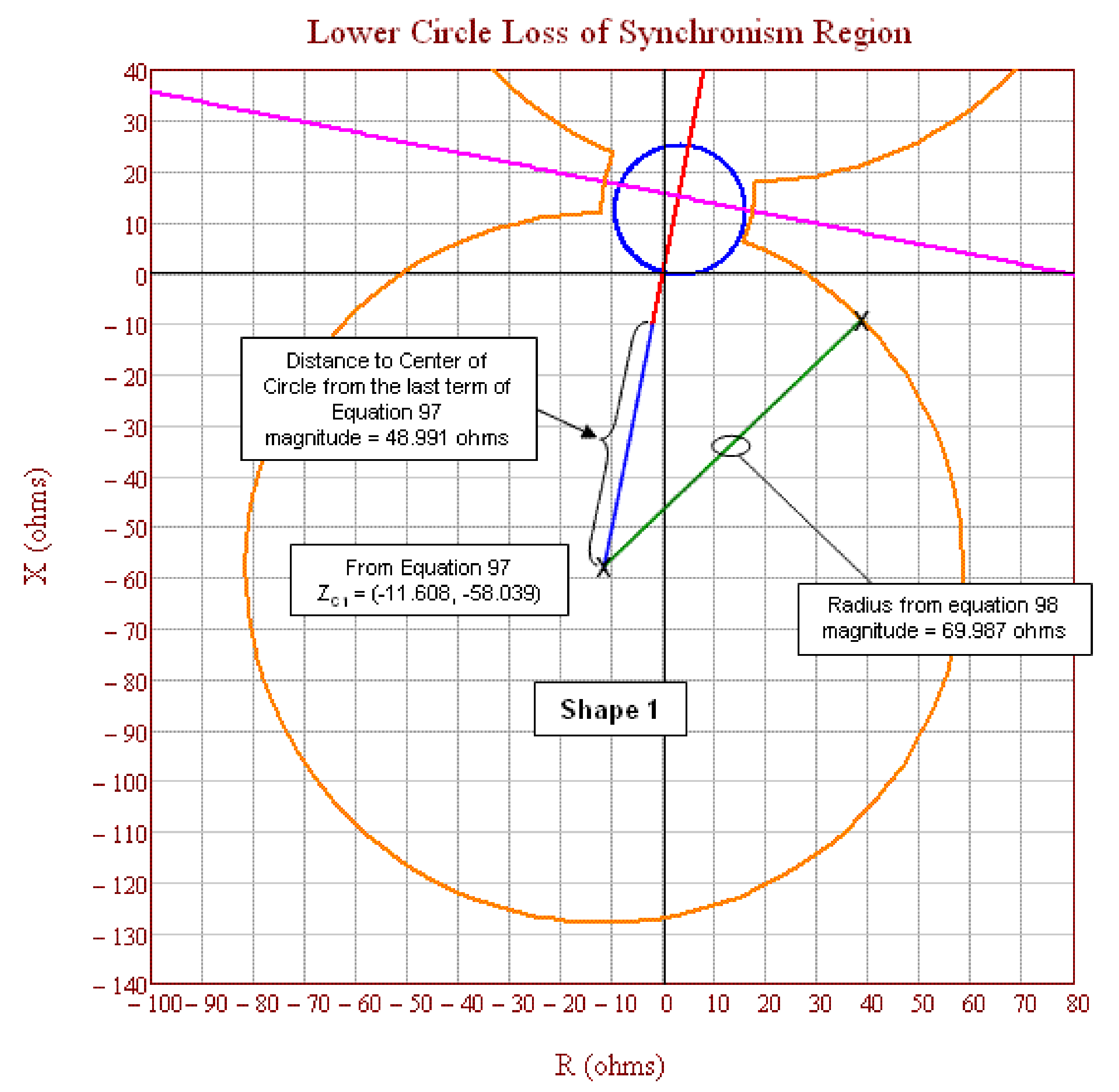


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

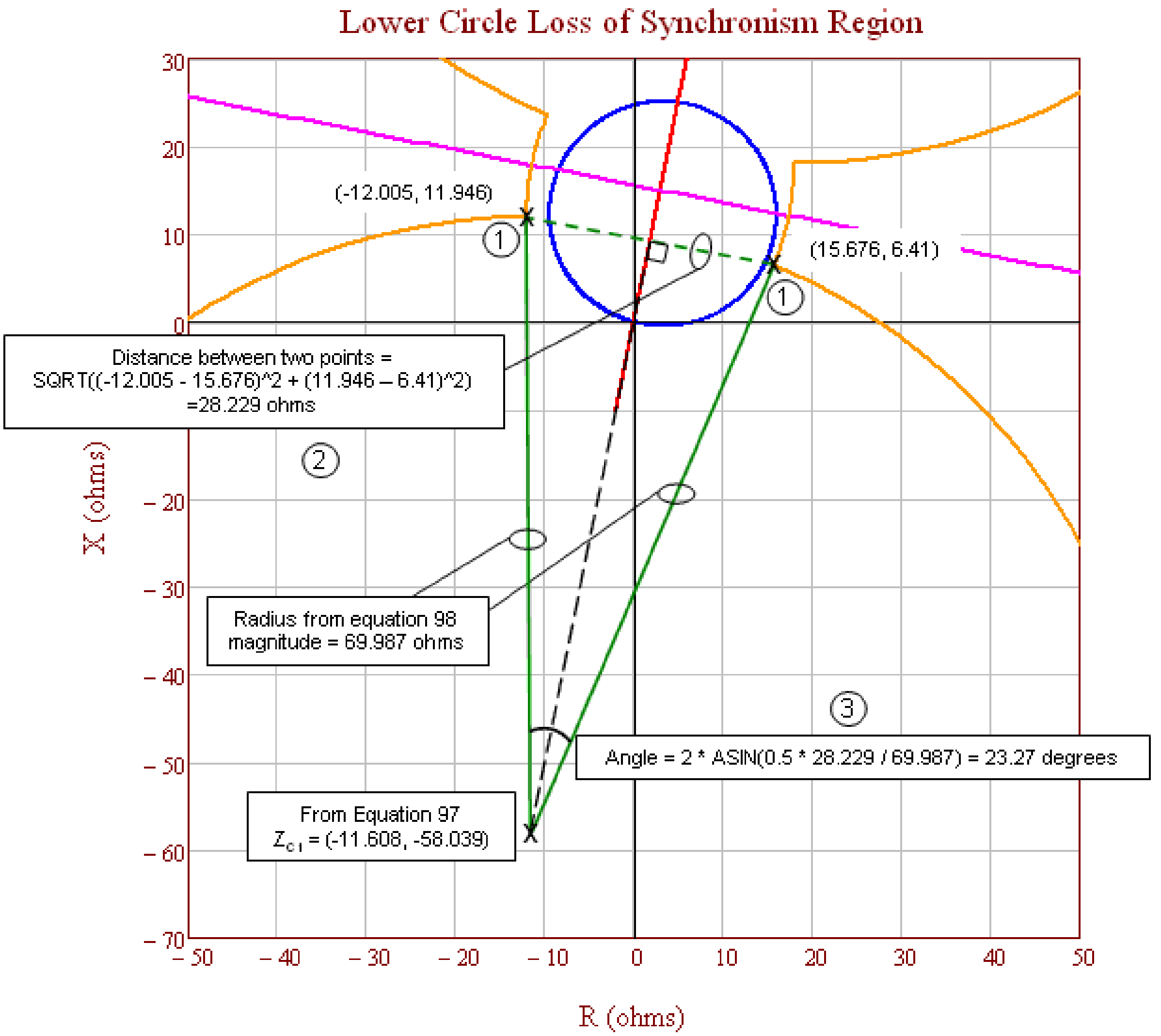


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

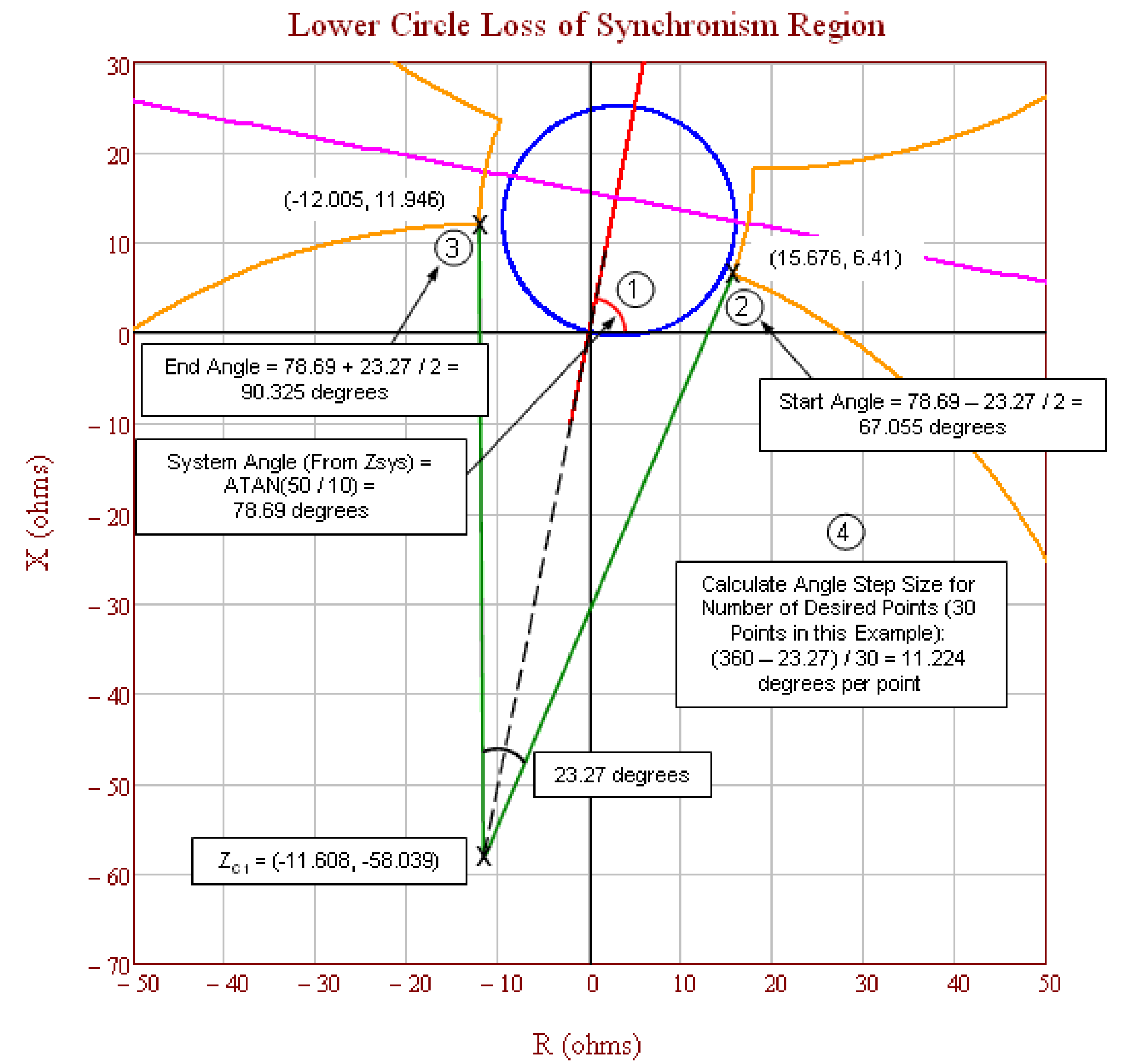


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

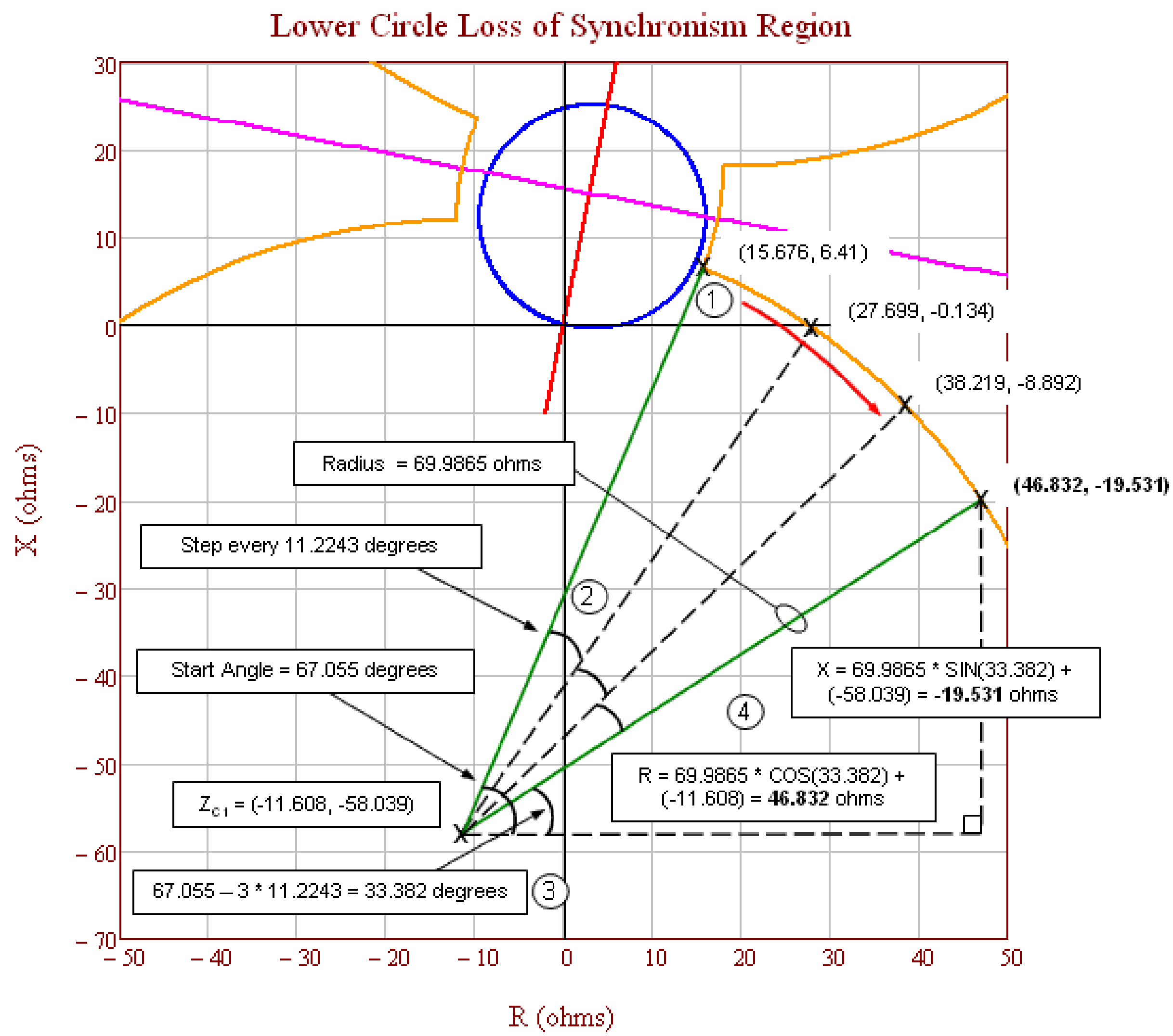


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

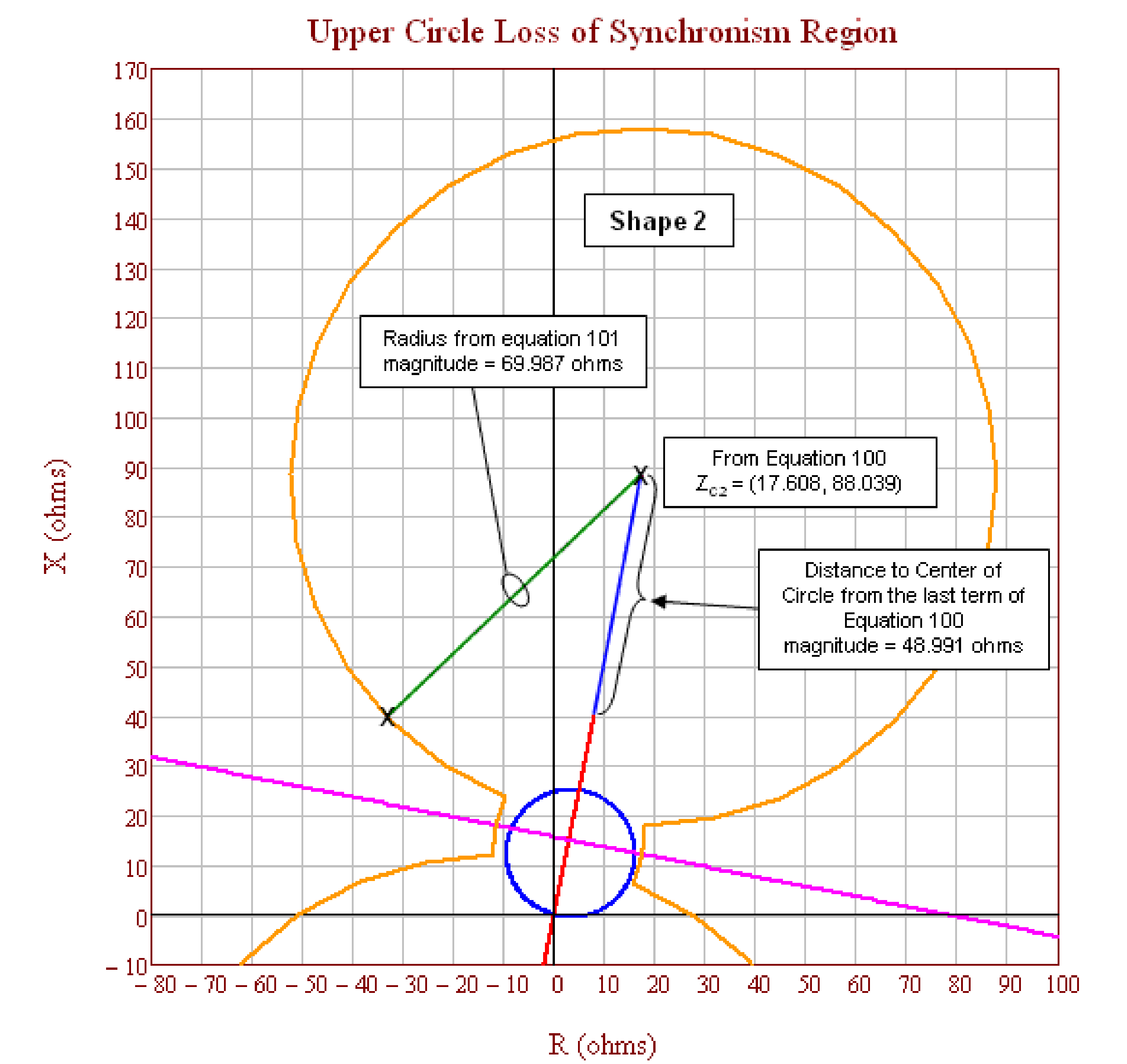


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

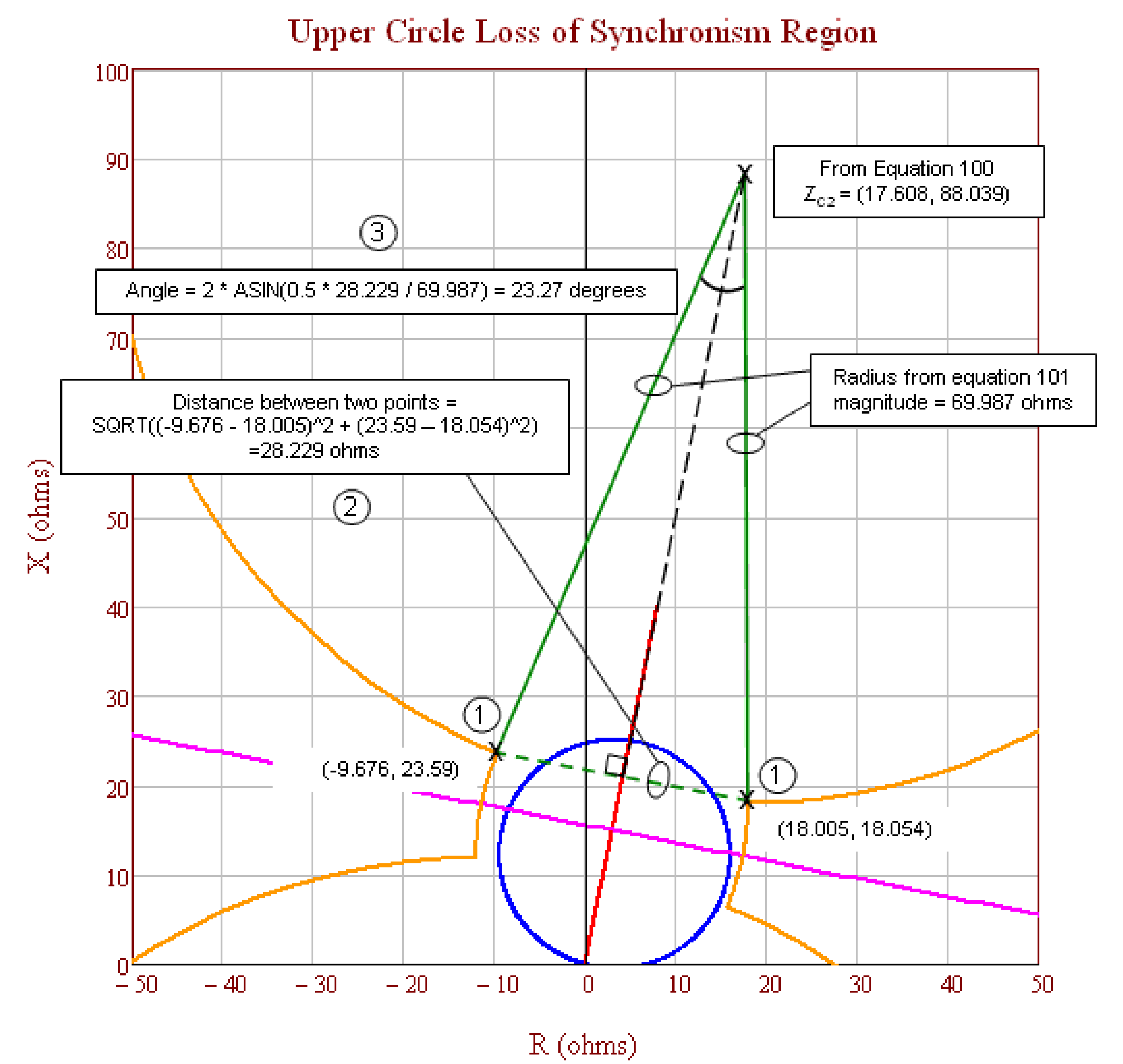


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

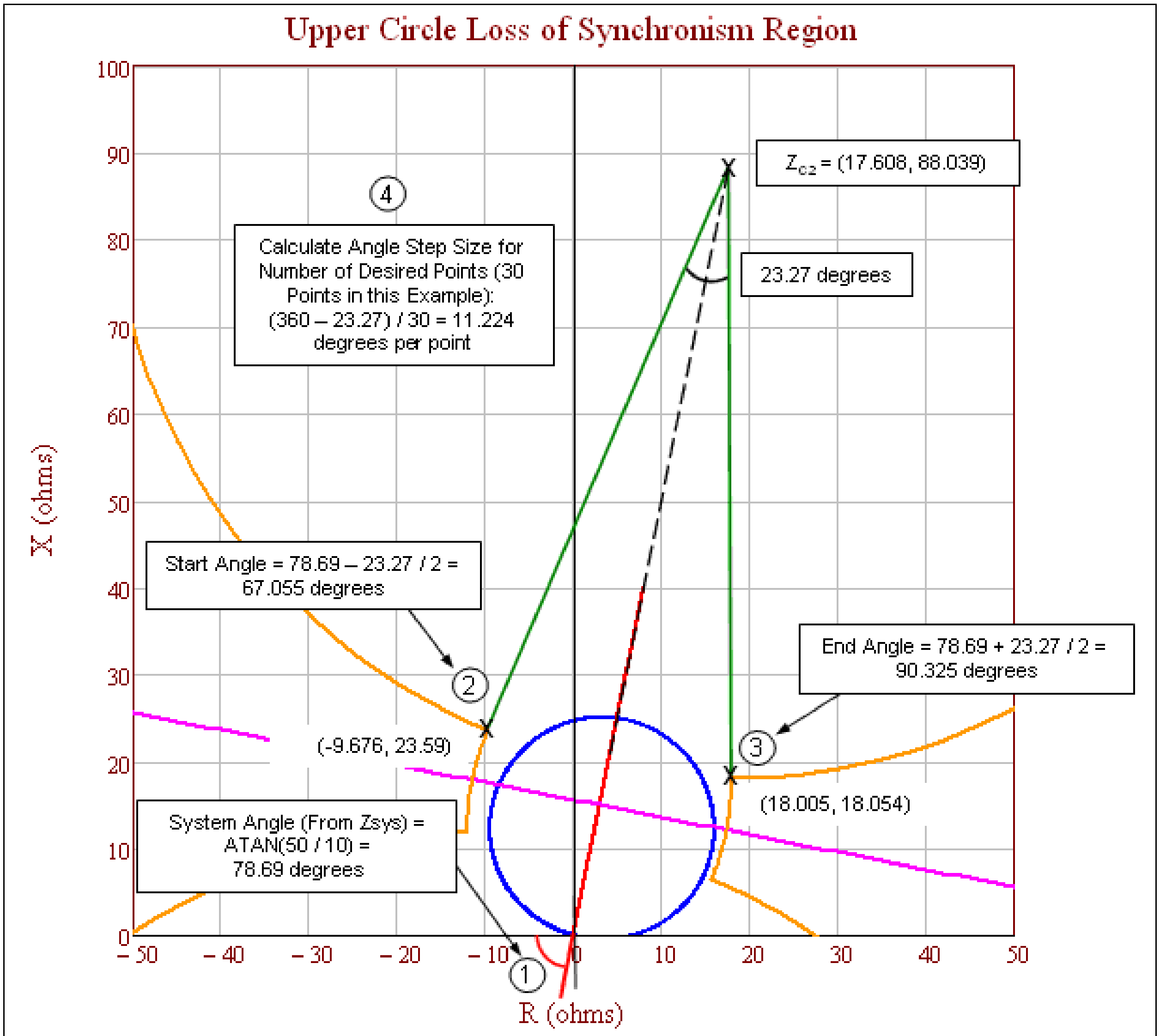


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

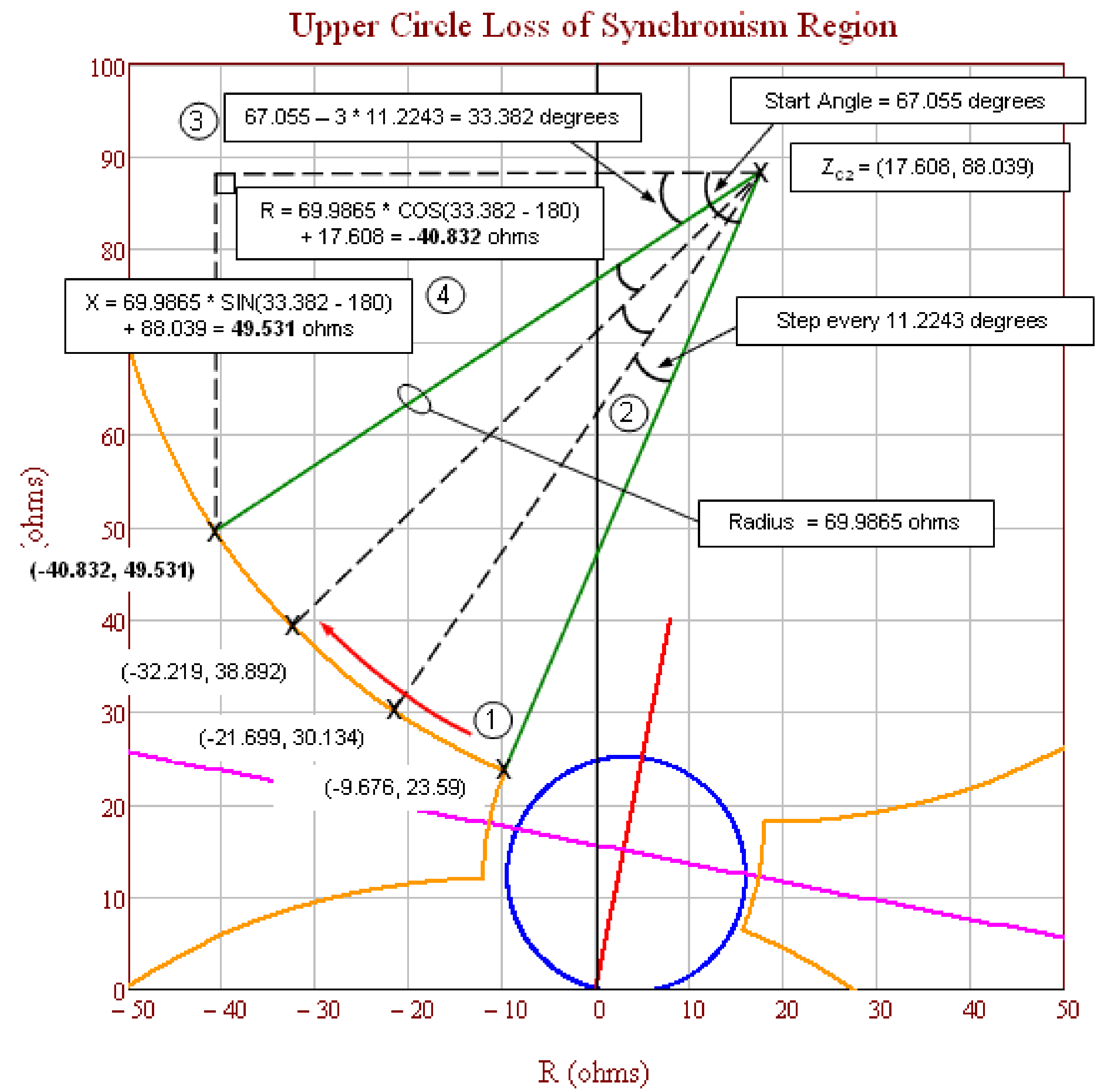


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-2 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

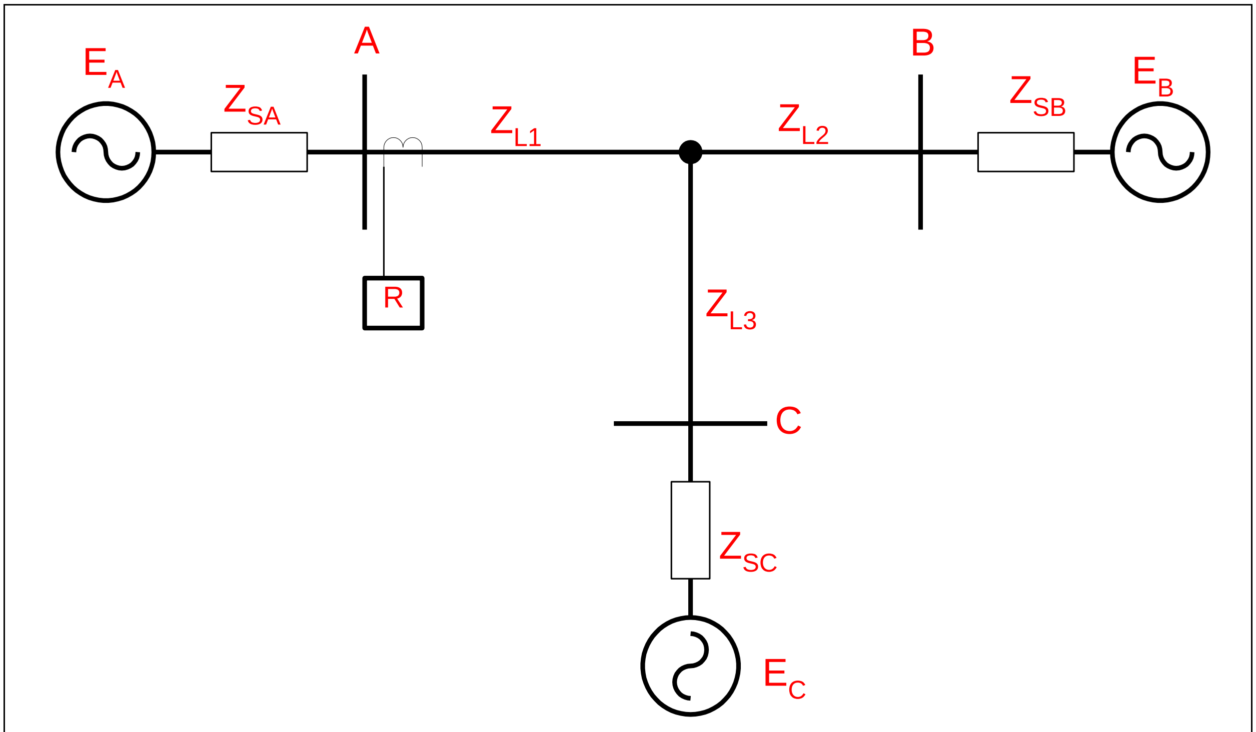


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

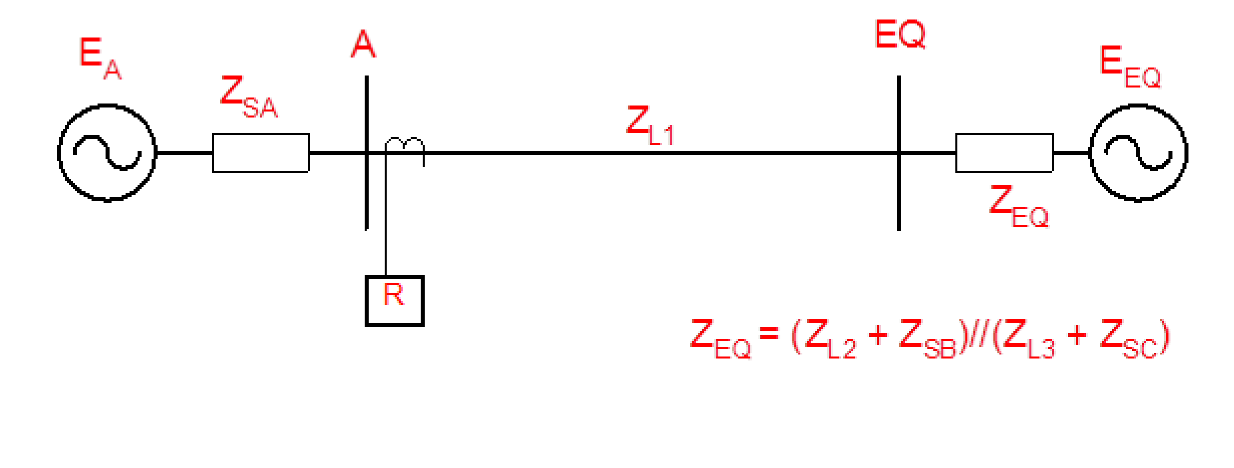


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

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[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

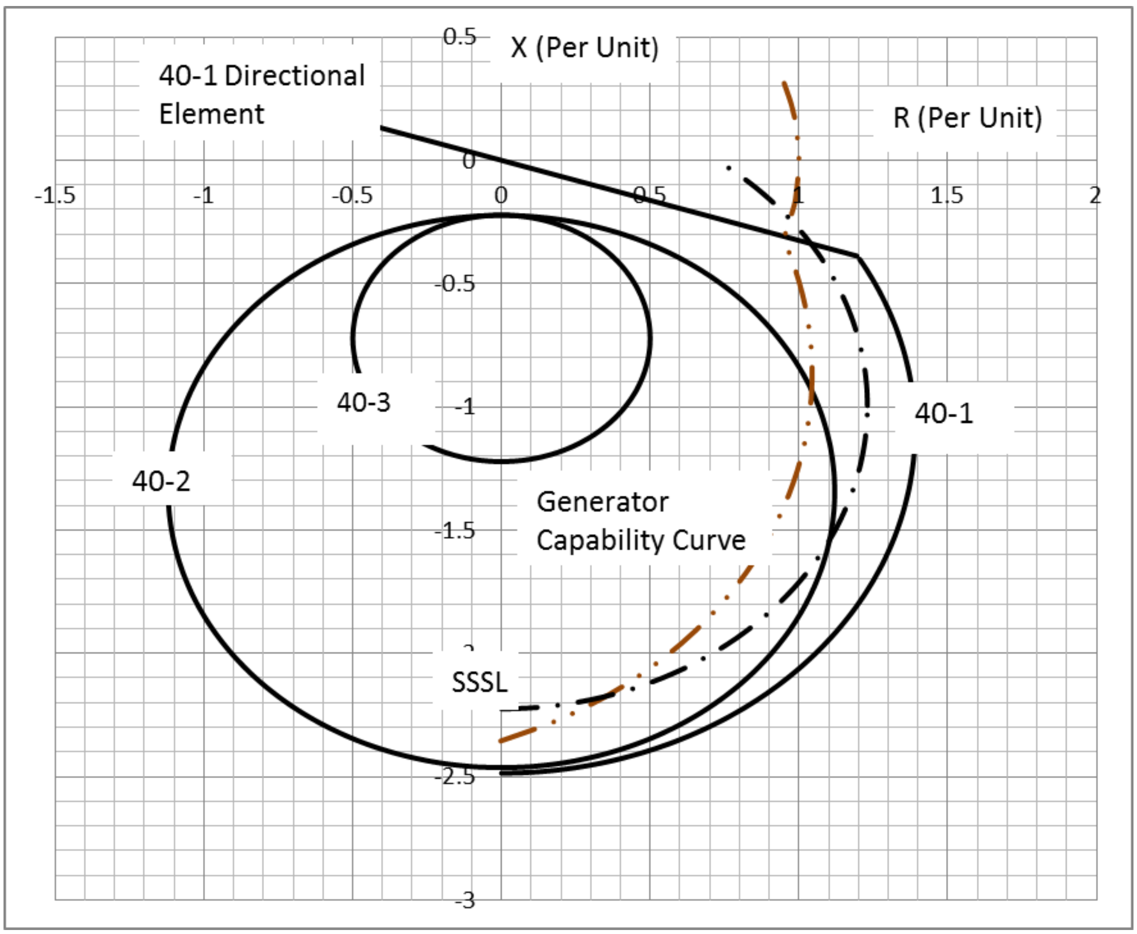

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

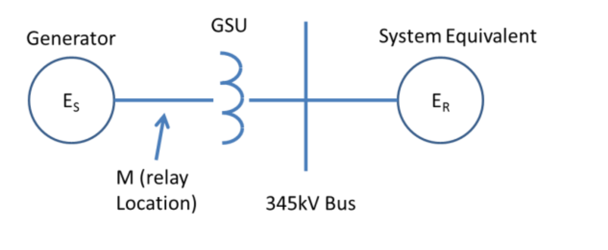

Figure 17: Simple one-line diagram of the system to be evaluated.

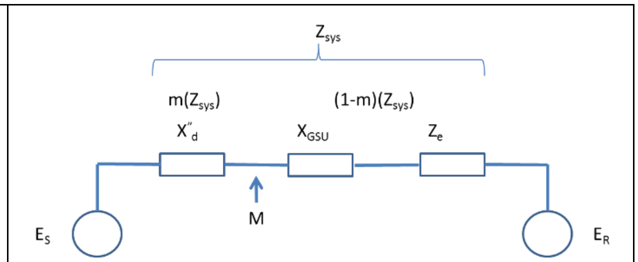

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) $=$ 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter $=$ 0.55 per unit
	MTA $=$ 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

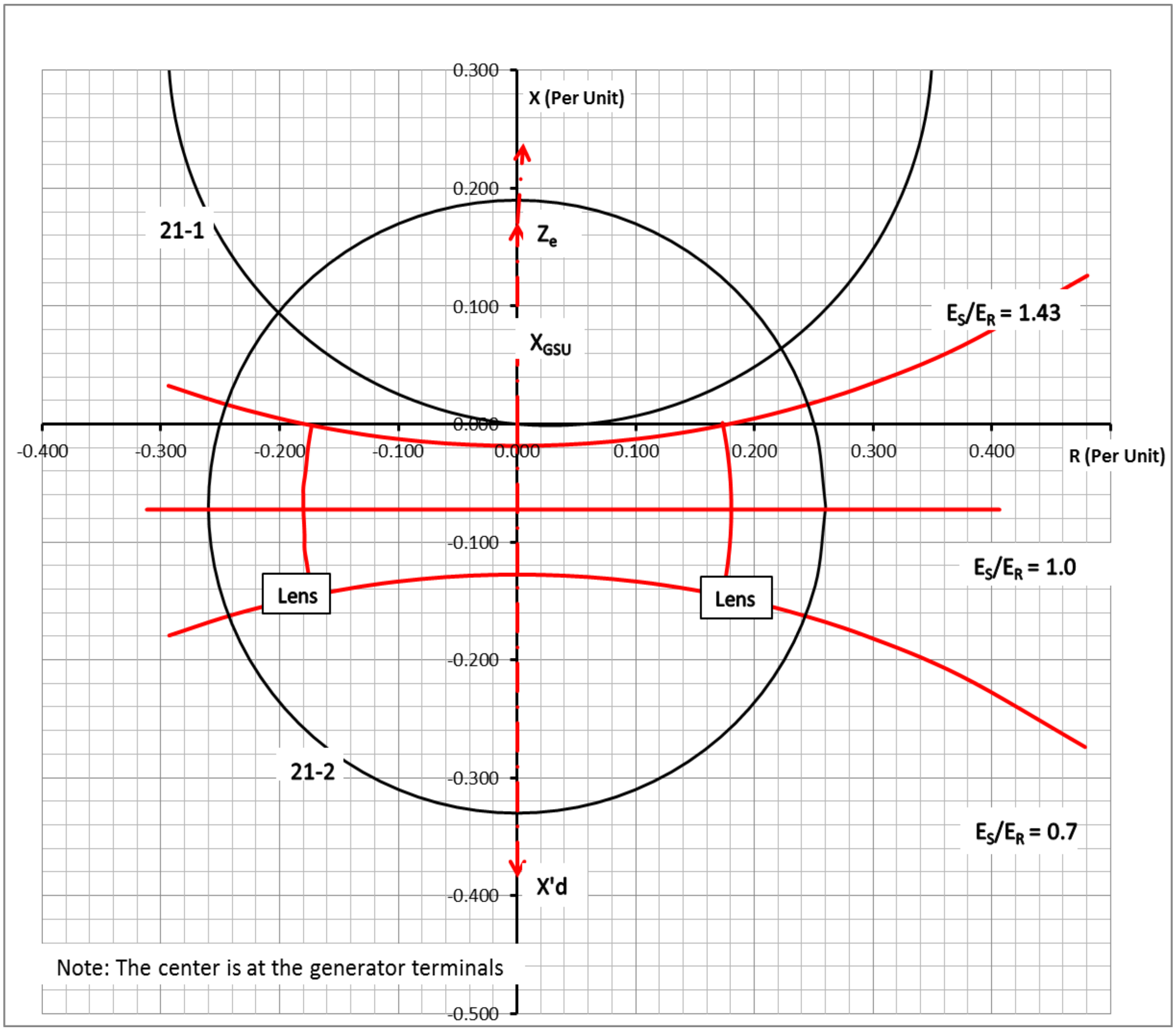

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

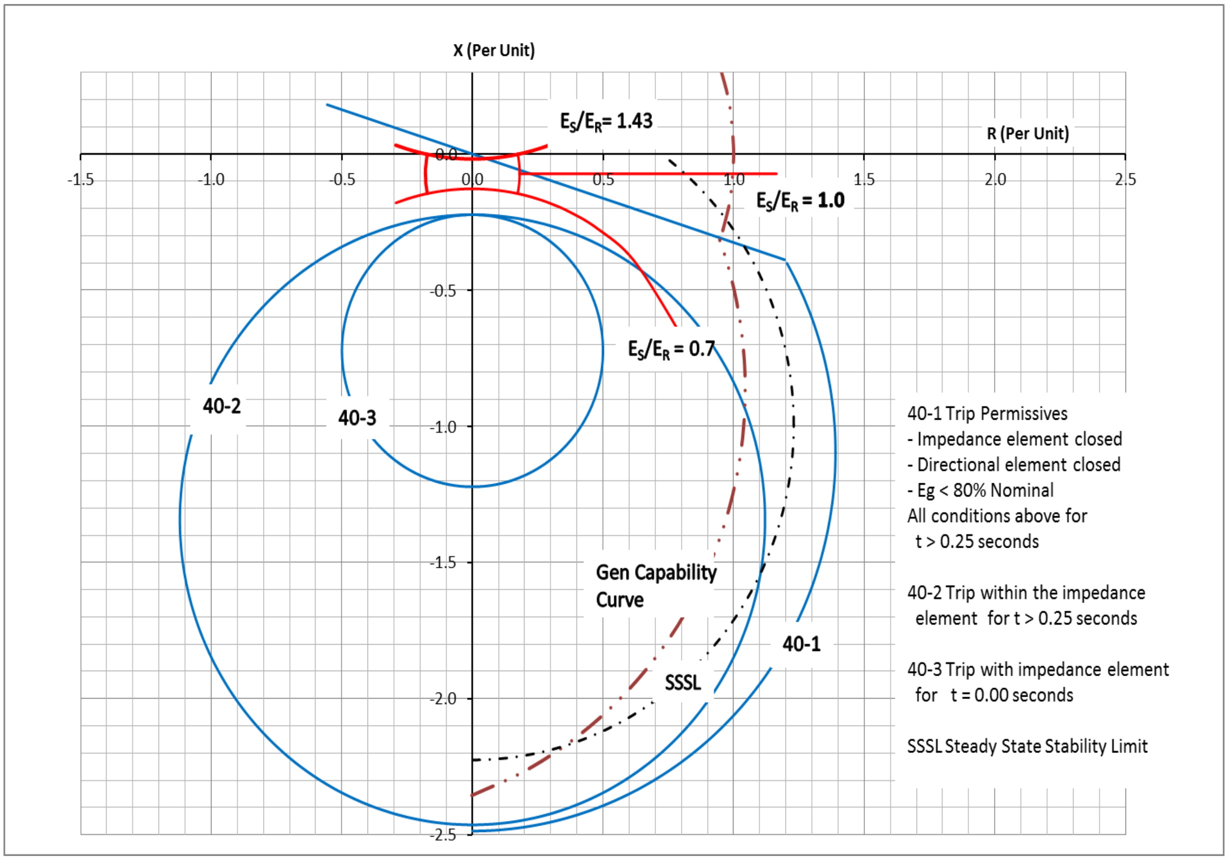

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer ($X_{T)}$, and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

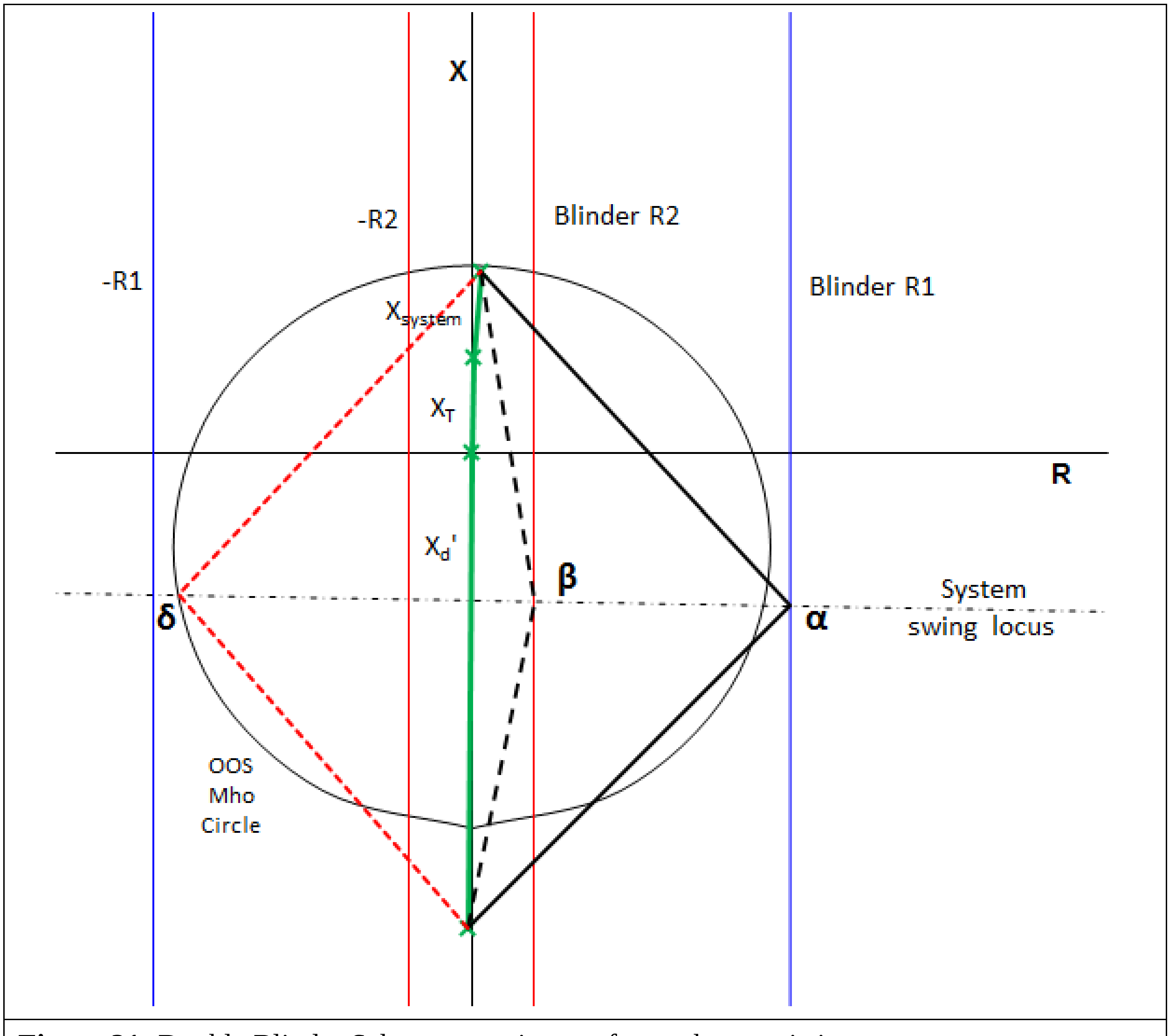

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

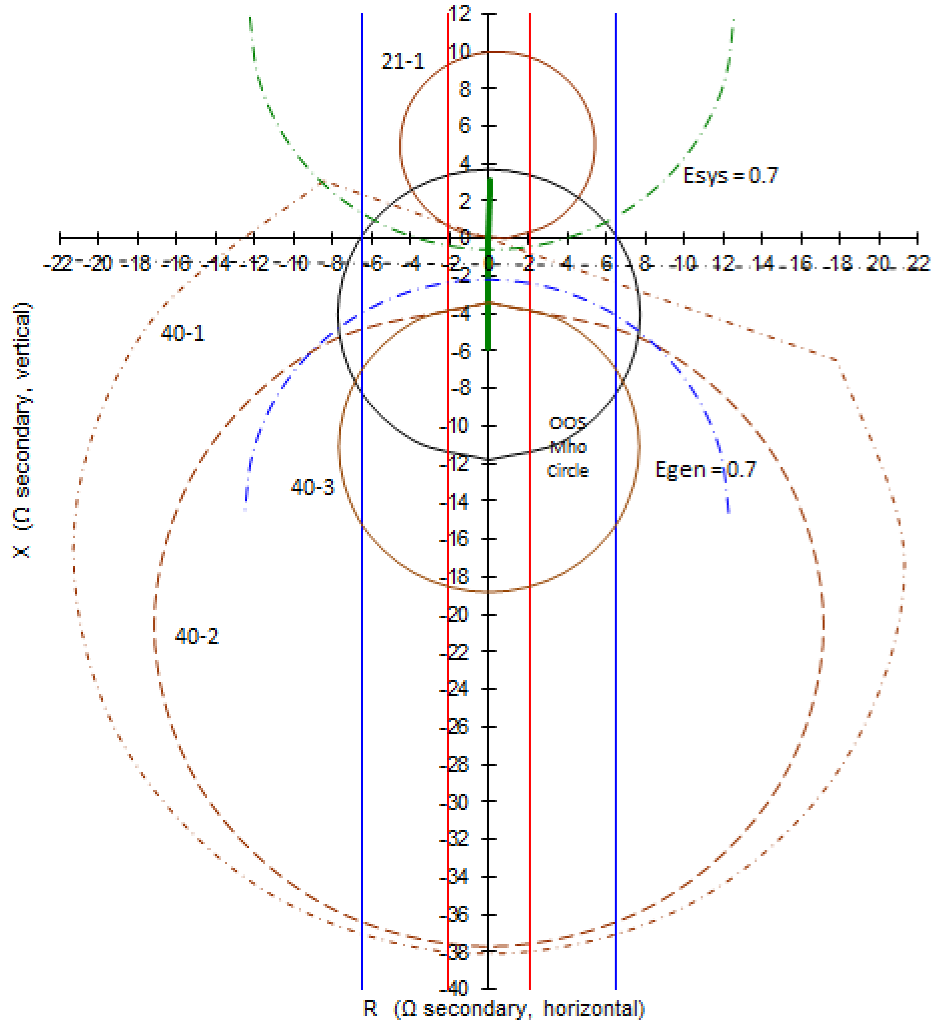

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-2 – Attachment B criteria or can be excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-2 – Attachment B criteria.

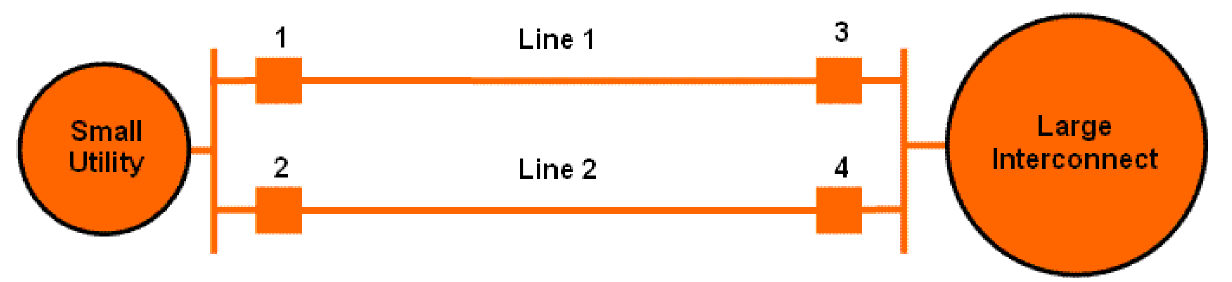

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

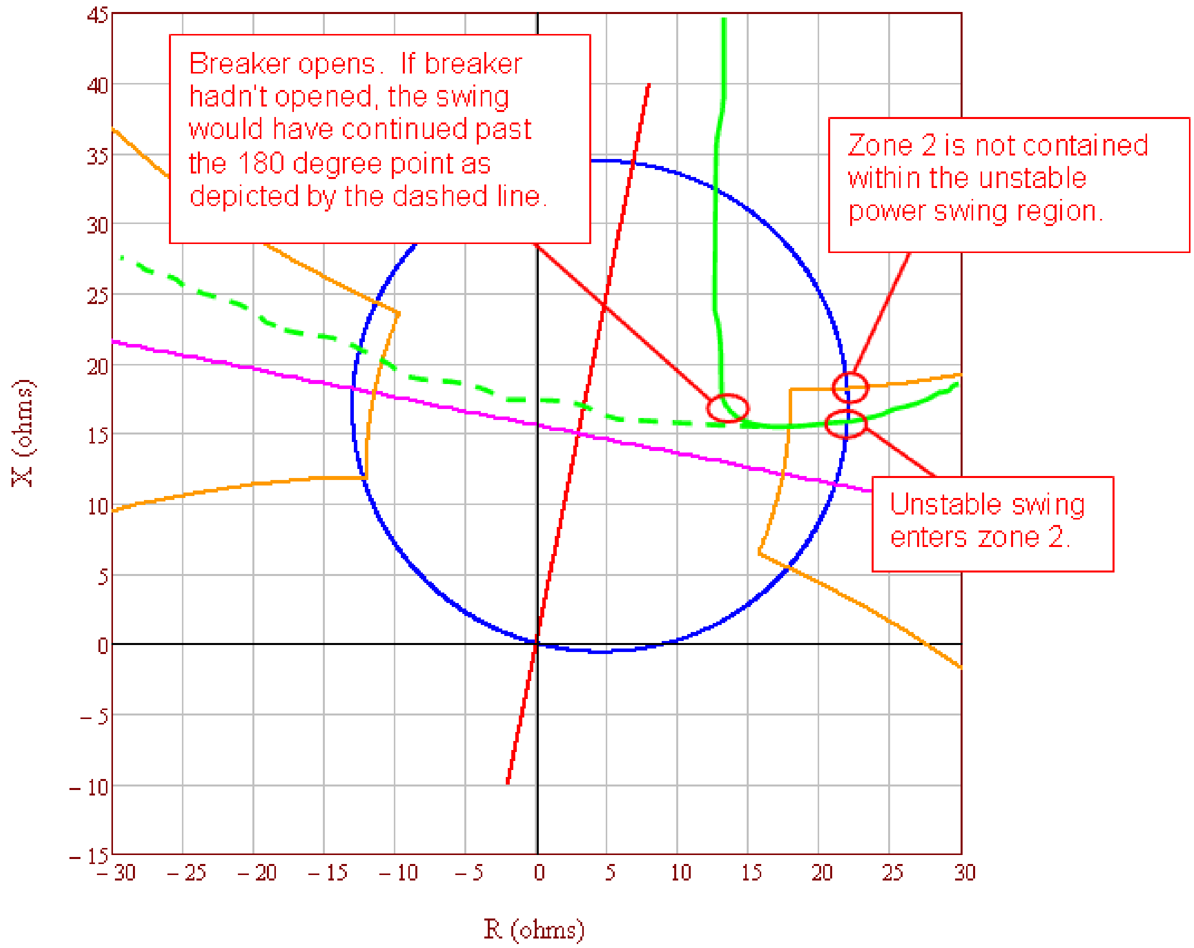

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

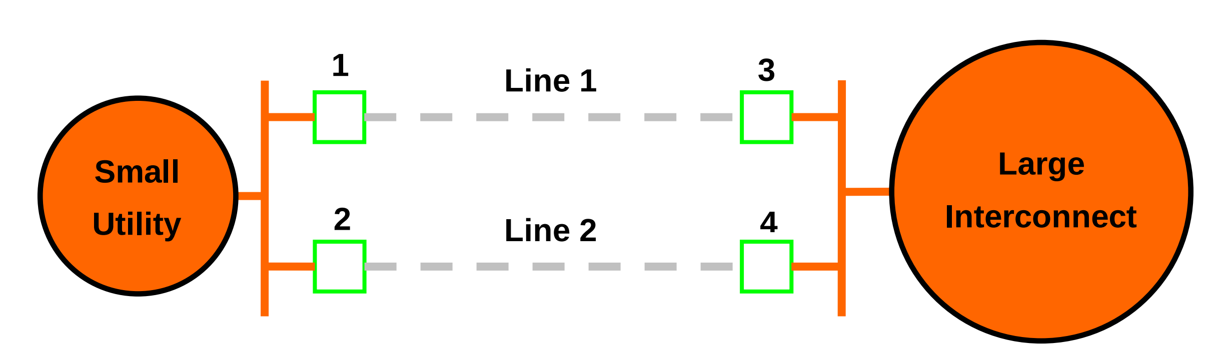

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

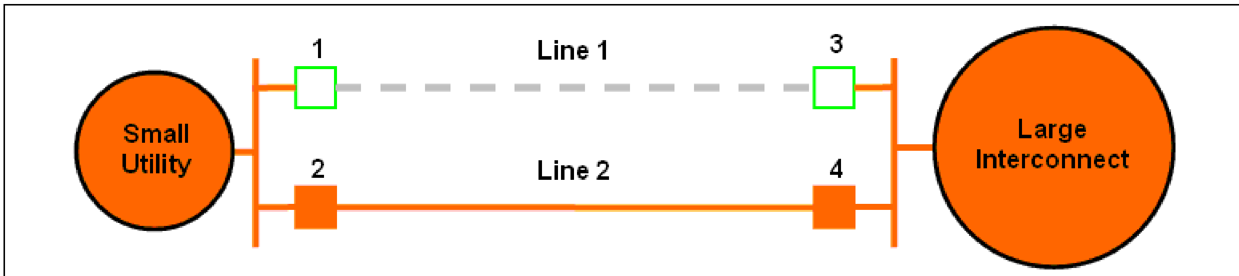

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

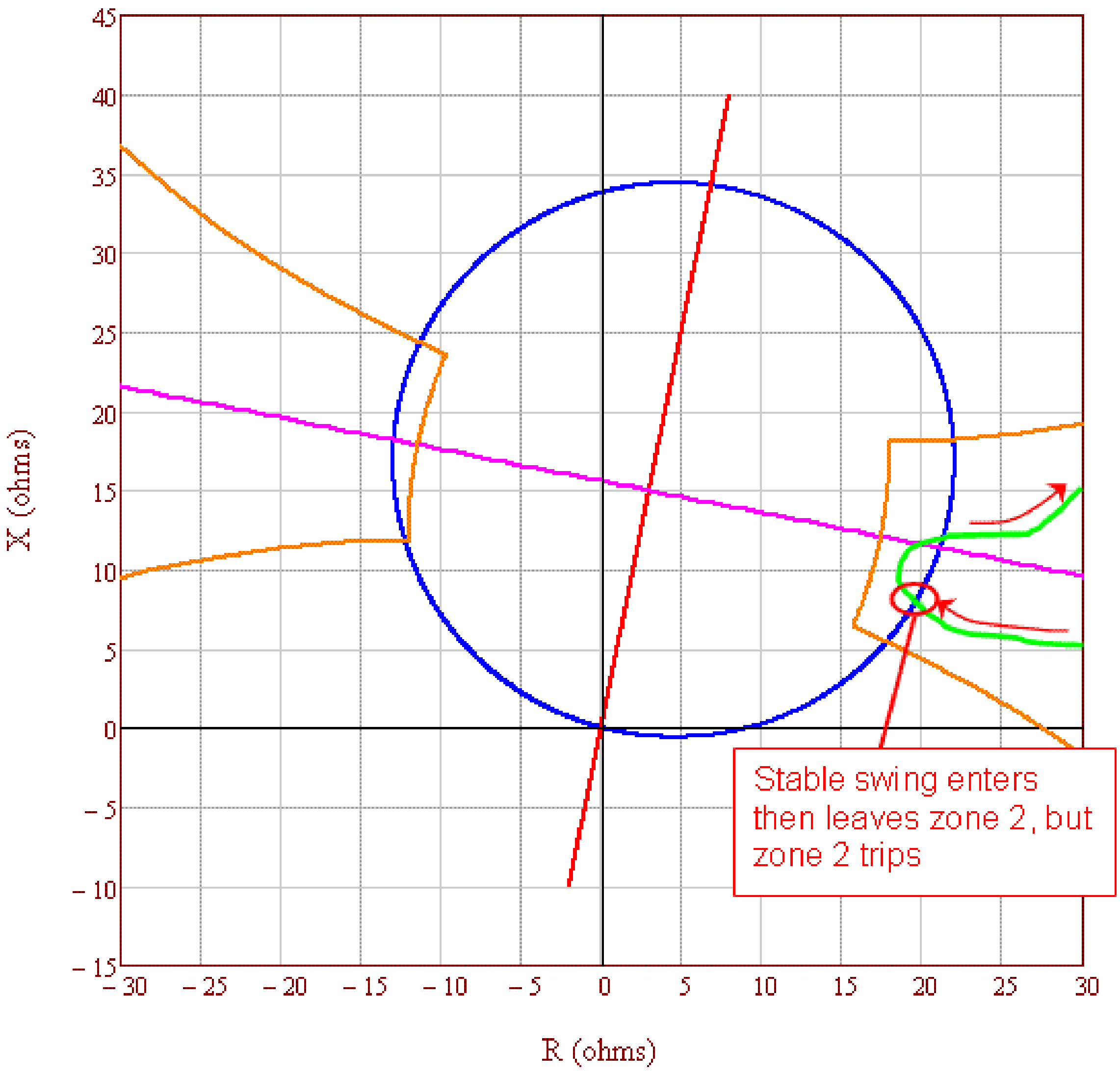

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

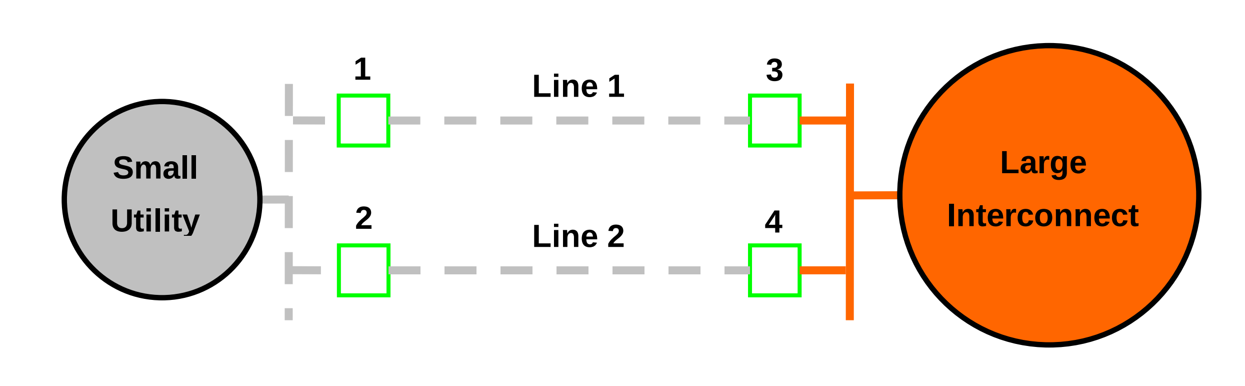

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

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[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2~~1~~**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. **Effective Dates:** See Implementation Plan

~~**Requirement R1**~~

~~First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**Requirements R2, R3, and R4**~~

~~First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. ~~An~~ Elements associated with ~~that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an~~ angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event.~~constraint~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

~~[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.~~

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-~~1~~2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-~~1~~2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-~~1~~2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

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Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	May 13, 2021	Adopted by NERC Board of Trustees	Revised under Project 2015-09

PRC-026-~~1~~ 2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-~~1~~2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-~~1~~ 2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "~~PRC-026-1~~PRC-026-2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-~~1~~2 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-~~1~~2 – Attachment B.

[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-~~1~~ 2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-~~1~~ 2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-~~1~~2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-~~1~~2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-~~1~~2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., $E_S / E_R = 0.7 / 1.0 = 0.7$). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., $E_S / E_R = 1.0 / 0.7 = 1.43$). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-~~1~~2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-~~1~~ 2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-~~1~~ 2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-~~1~~ 2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-~~1~~ 2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements*, April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-~~1~~ 2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-~~1~~ 2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-~~1~~ 2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-~~1~~ 2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

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[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

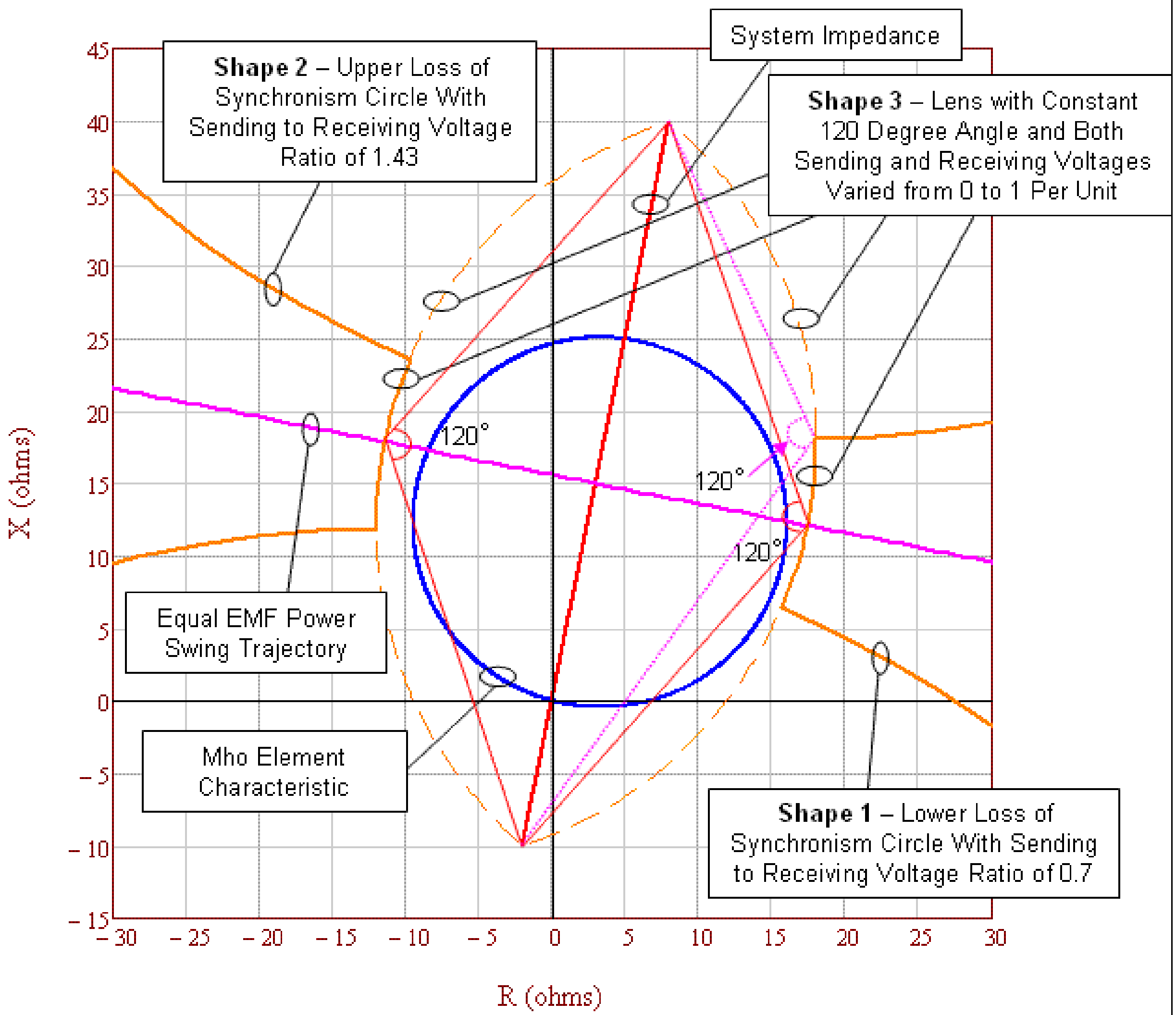


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1.

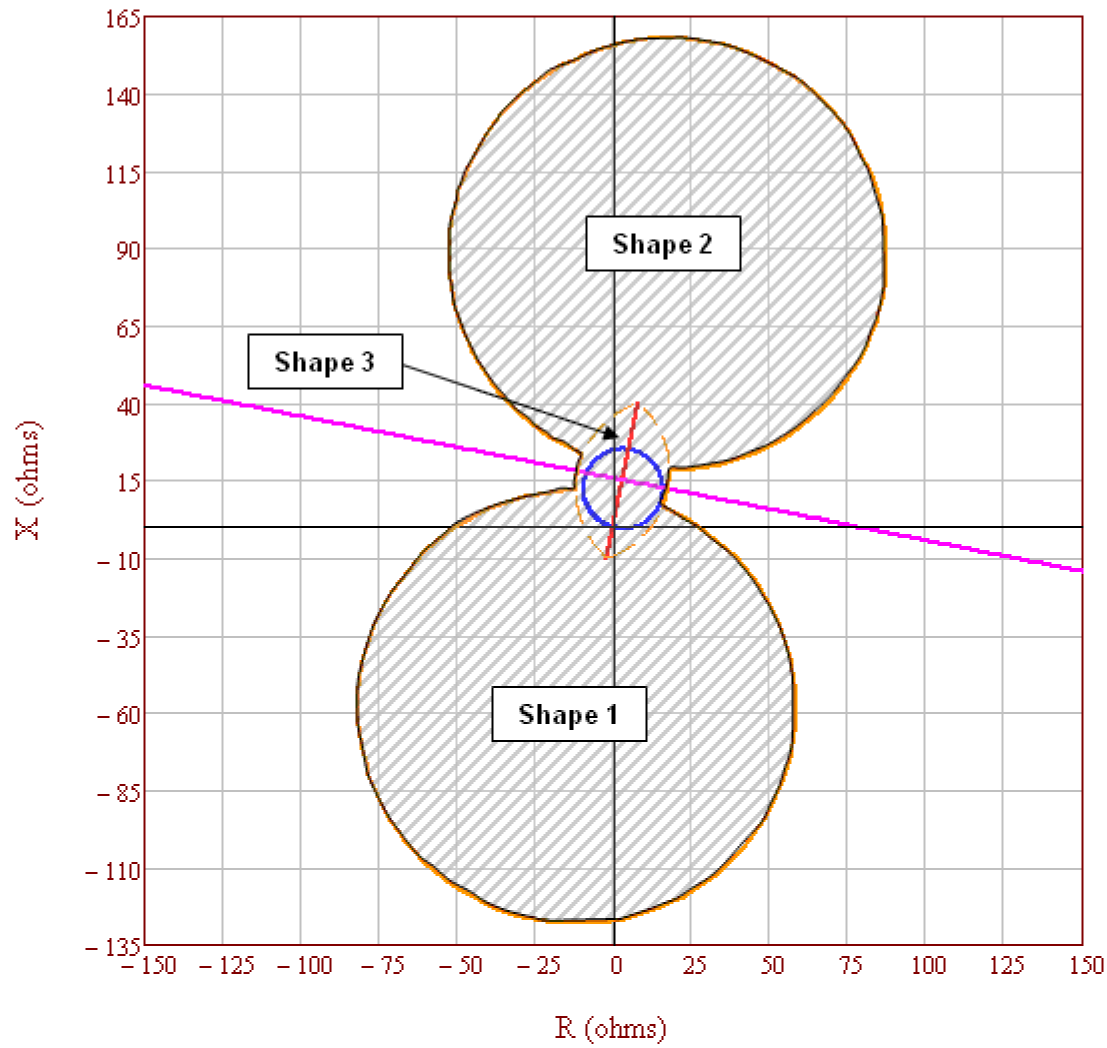


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

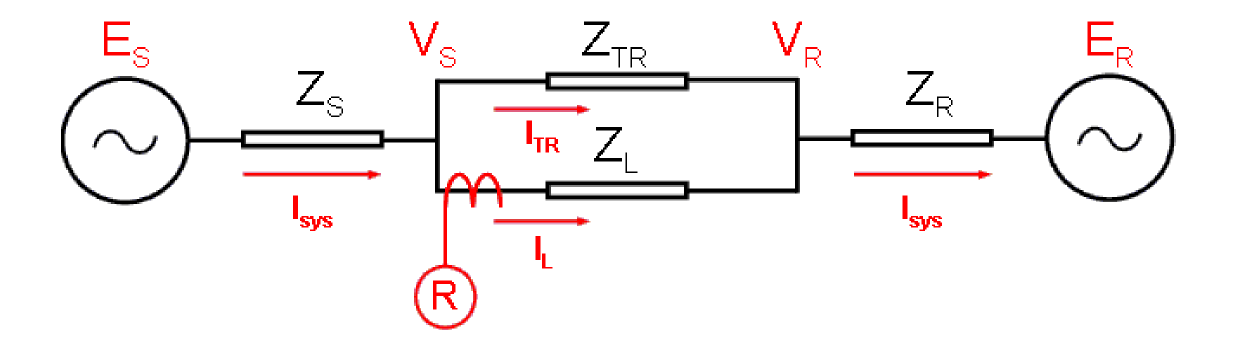


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

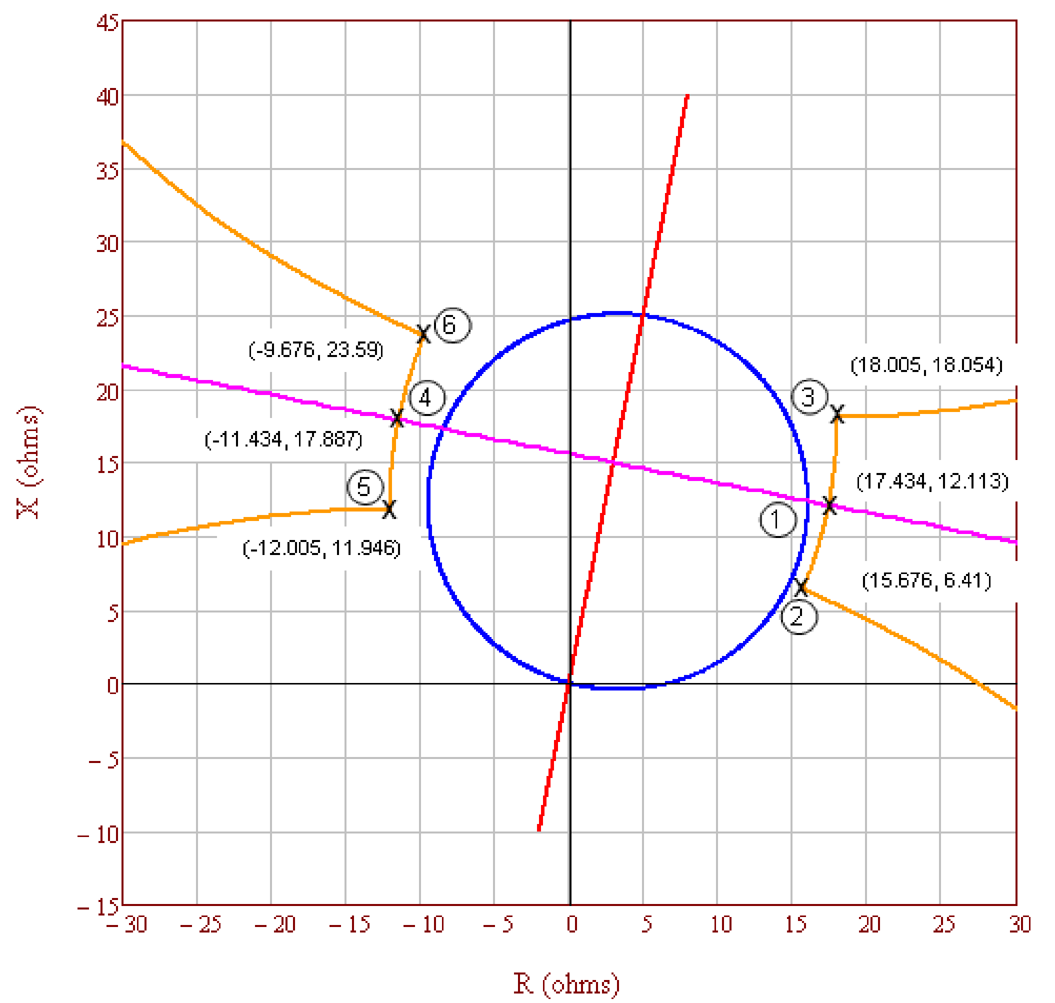


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

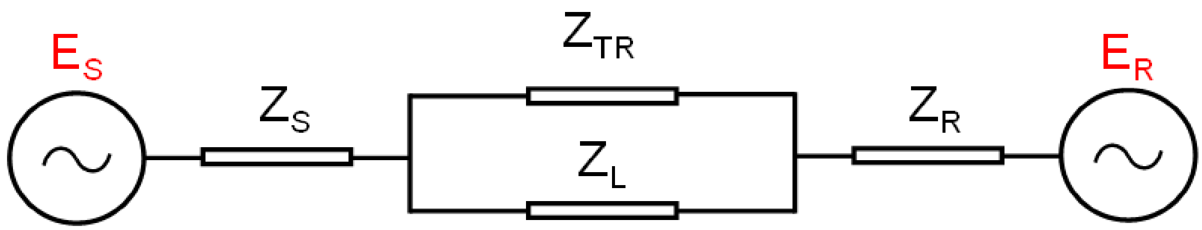
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}511\angle 131.1°\ A]$
	$V_S = 95{,}756\angle -106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1°\ V}{4{,}511\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{((4+j20)\,\Omega \times (4+j20) \times 10^{10}\,\Omega)}{((4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega)}$
	$Z_{total} = 4 + j20\,\Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\,\Omega) + (4 + j20\,\Omega) + (4 + j20\,\Omega)$
	$Z_{sys} = 10 + j50\,\Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\,V - 132{,}791\angle 0°\,V}{10 + j50\,\Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\,A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\,A \times \frac{(4+j20) \times 10^{10}\,\Omega}{(4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega}$
	$I_L = 3{,}854\angle 125.5°\,A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\,V - [(2 + j10\,)\,\Omega \times 3{,}854\angle 125.5°\,A]$
	$V_S = 65{,}270.5\angle -99.4°\,V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\,V}{3{,}854\angle 125.5°\,A}$
	$Z_{L-Relay} = -12.005 + j11.946\,\Omega$

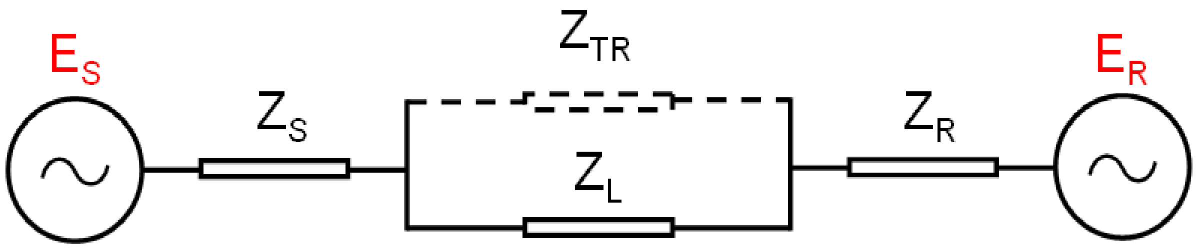
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle - 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

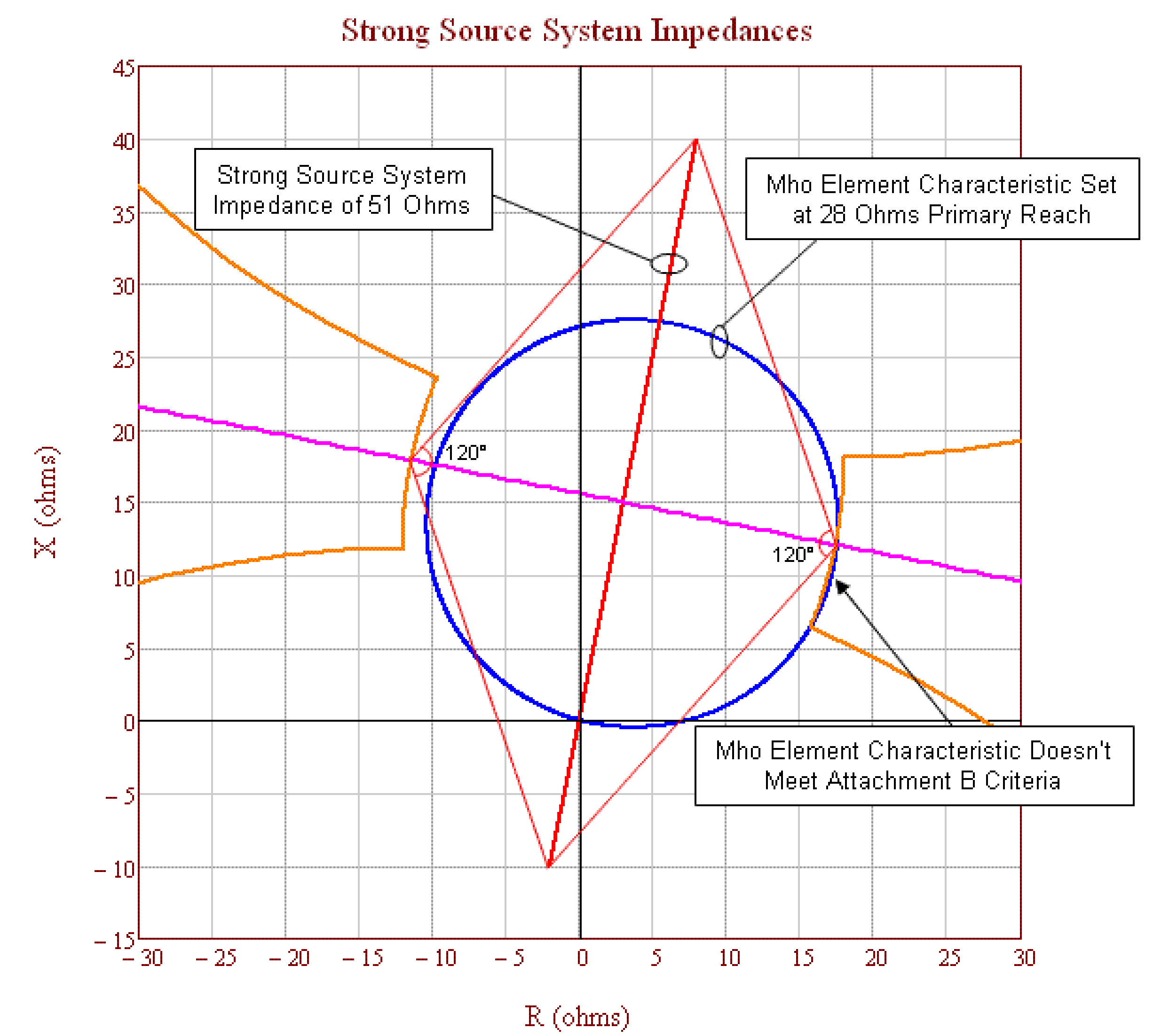


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-~~1~~2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

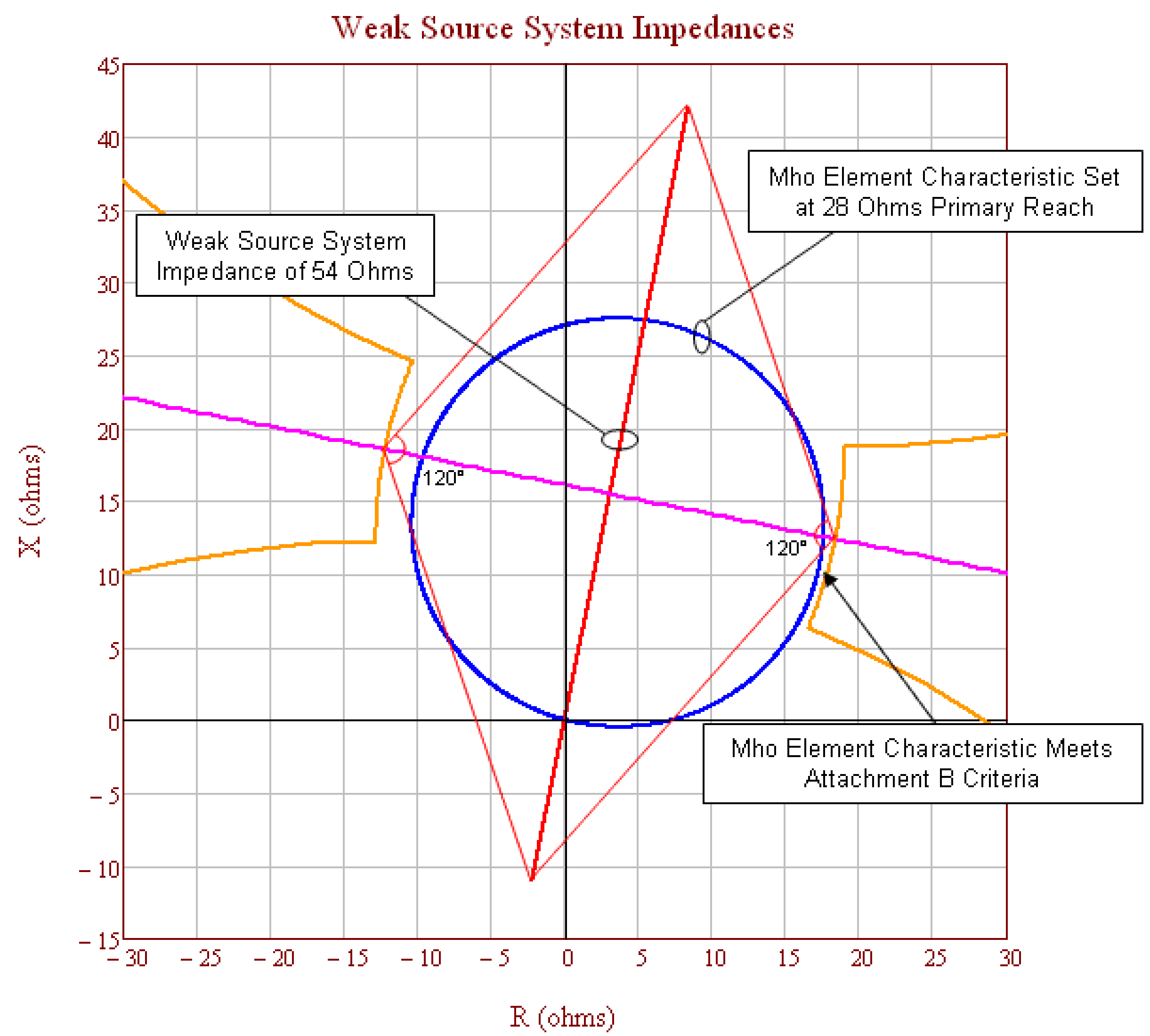


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

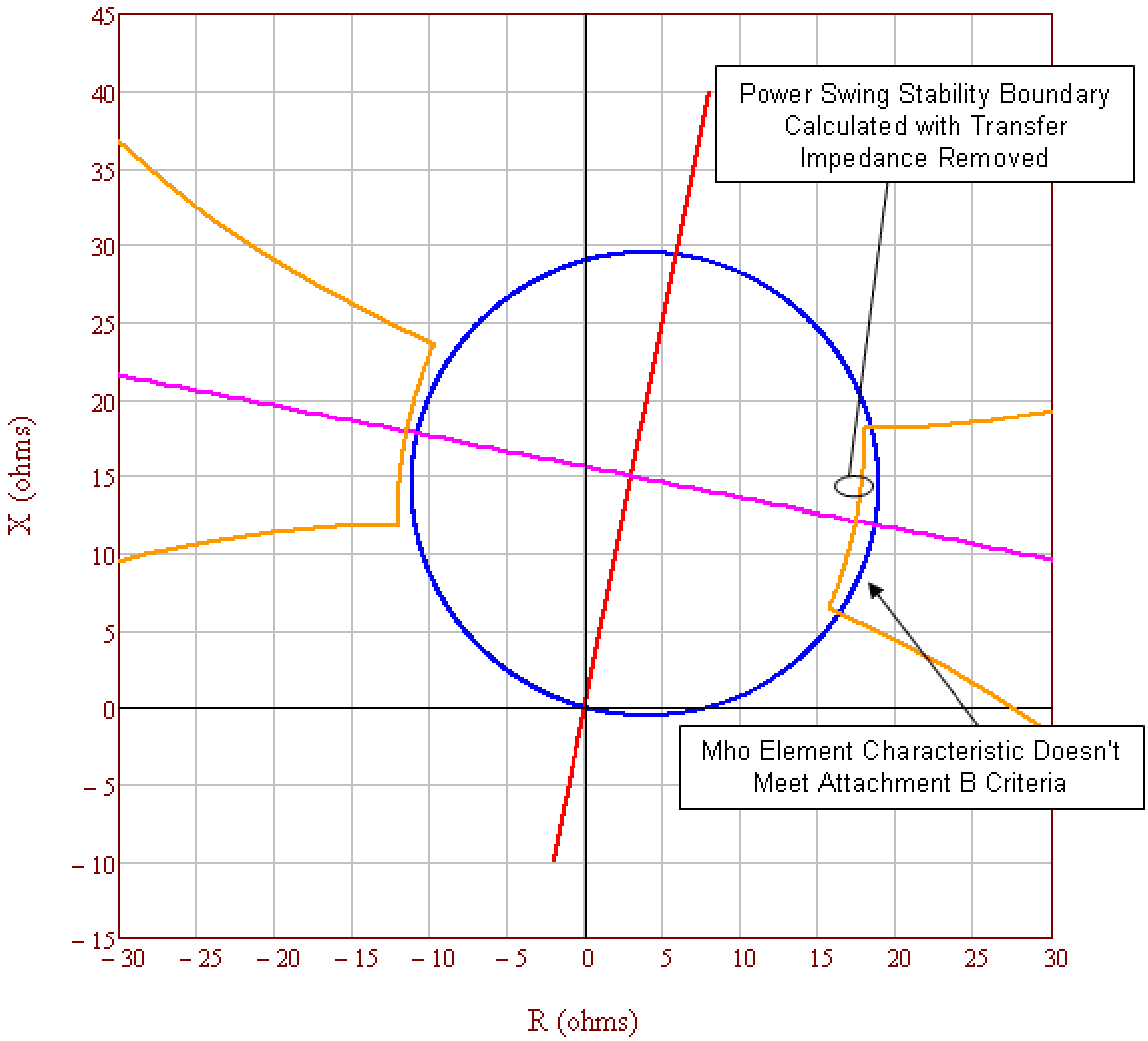


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

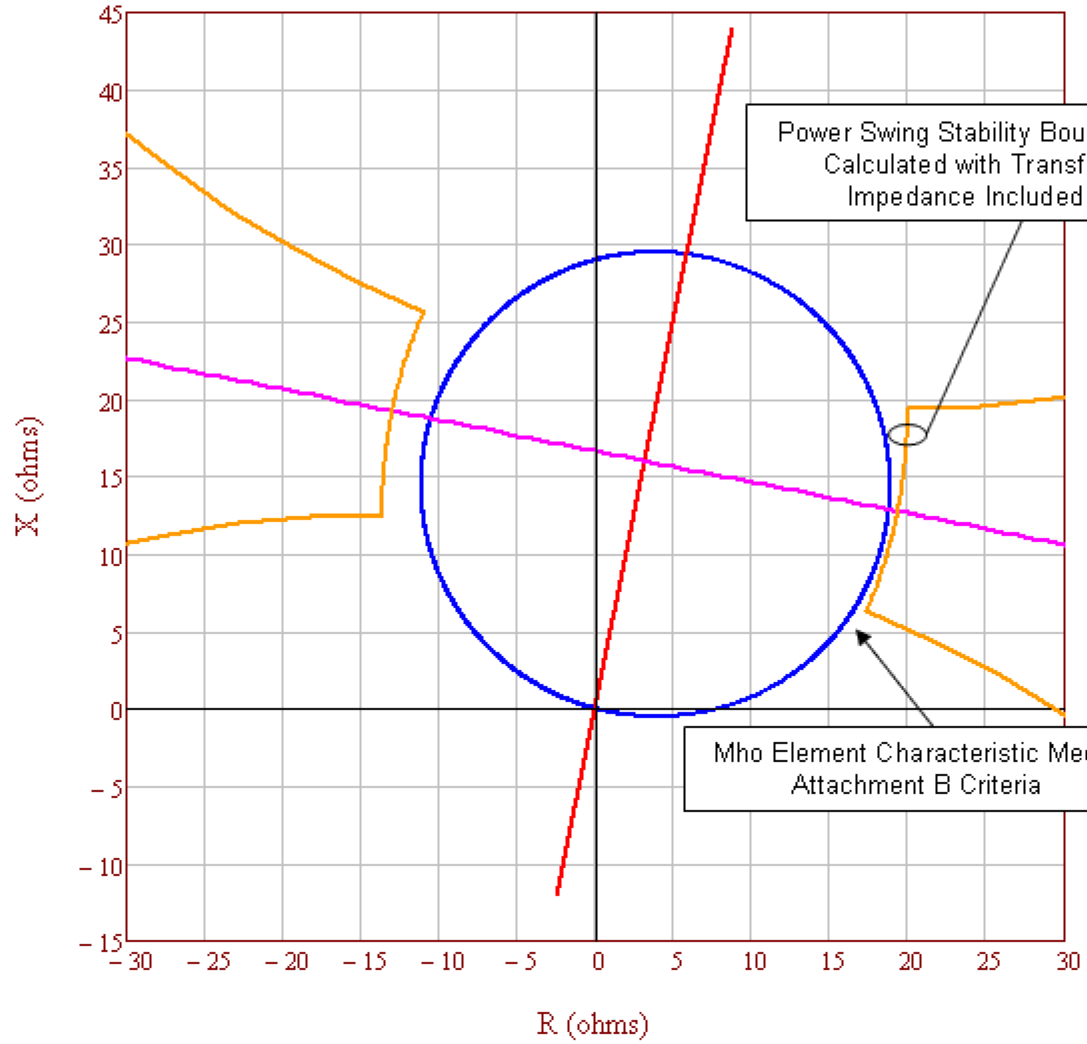


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-~~1~~2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \dfrac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

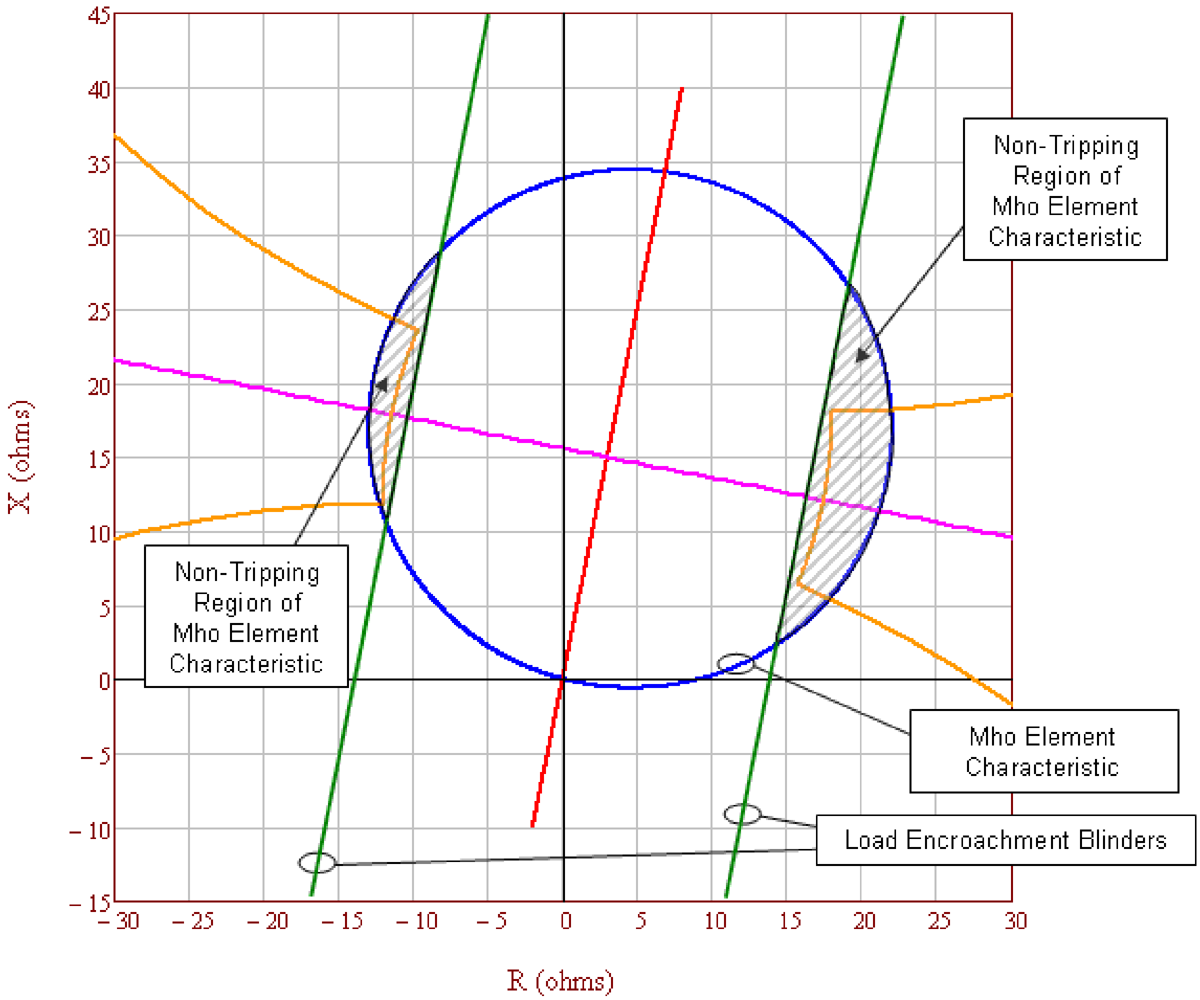


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-~~1~~ 2– Attachment B, Criterion A.

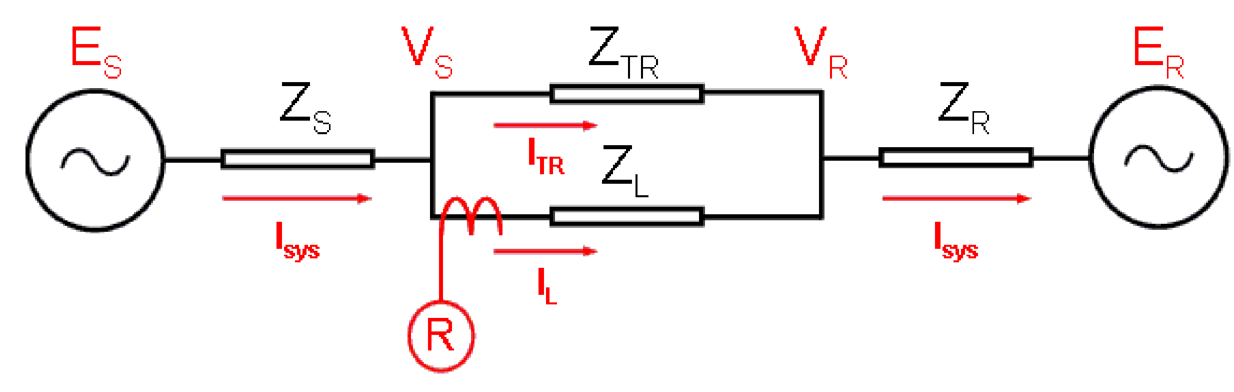


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \dfrac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \dfrac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \dfrac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \dfrac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \dfrac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \dfrac{V_S}{I_L} = Z_L + Z_R + \dfrac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

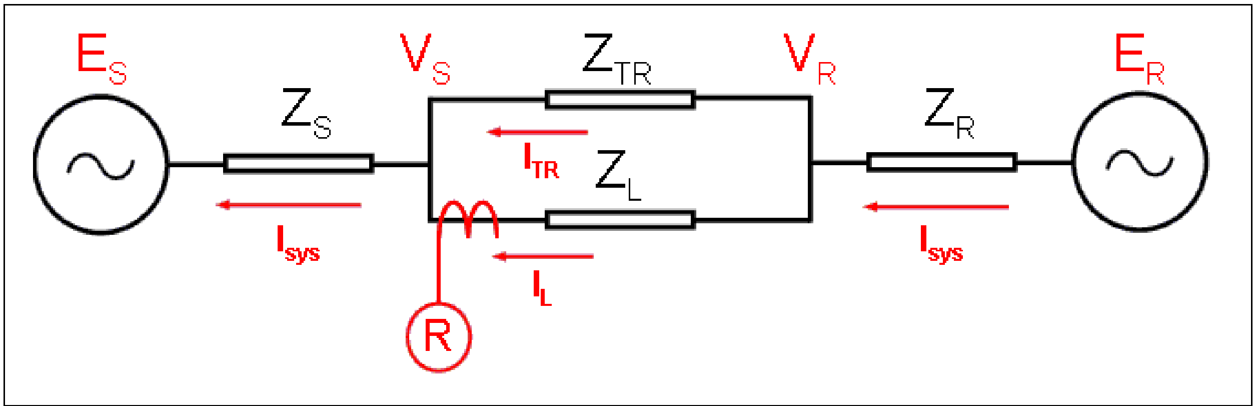


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

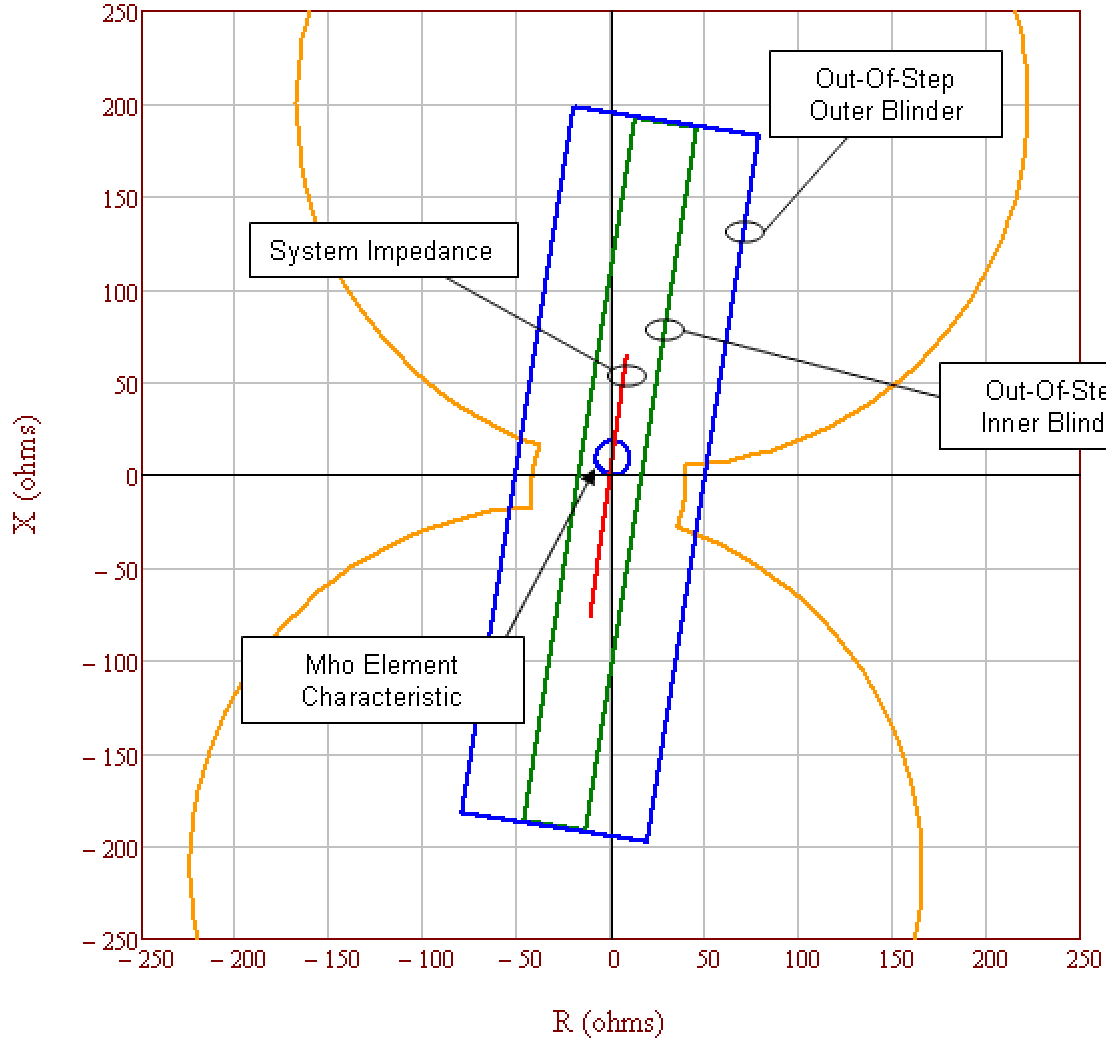


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S\rvert}{\lvert E_R\rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert\frac{N \times Z_{sys}}{1 - N^2}\right\rvert$		
	$r_a = \left\lvert\frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert\frac{N \times Z_{sys}}{N^2 - 1}\right\rvert$
	$r_b = \left\lvert\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right\rvert$
	$r_b = 69.987\ \Omega$

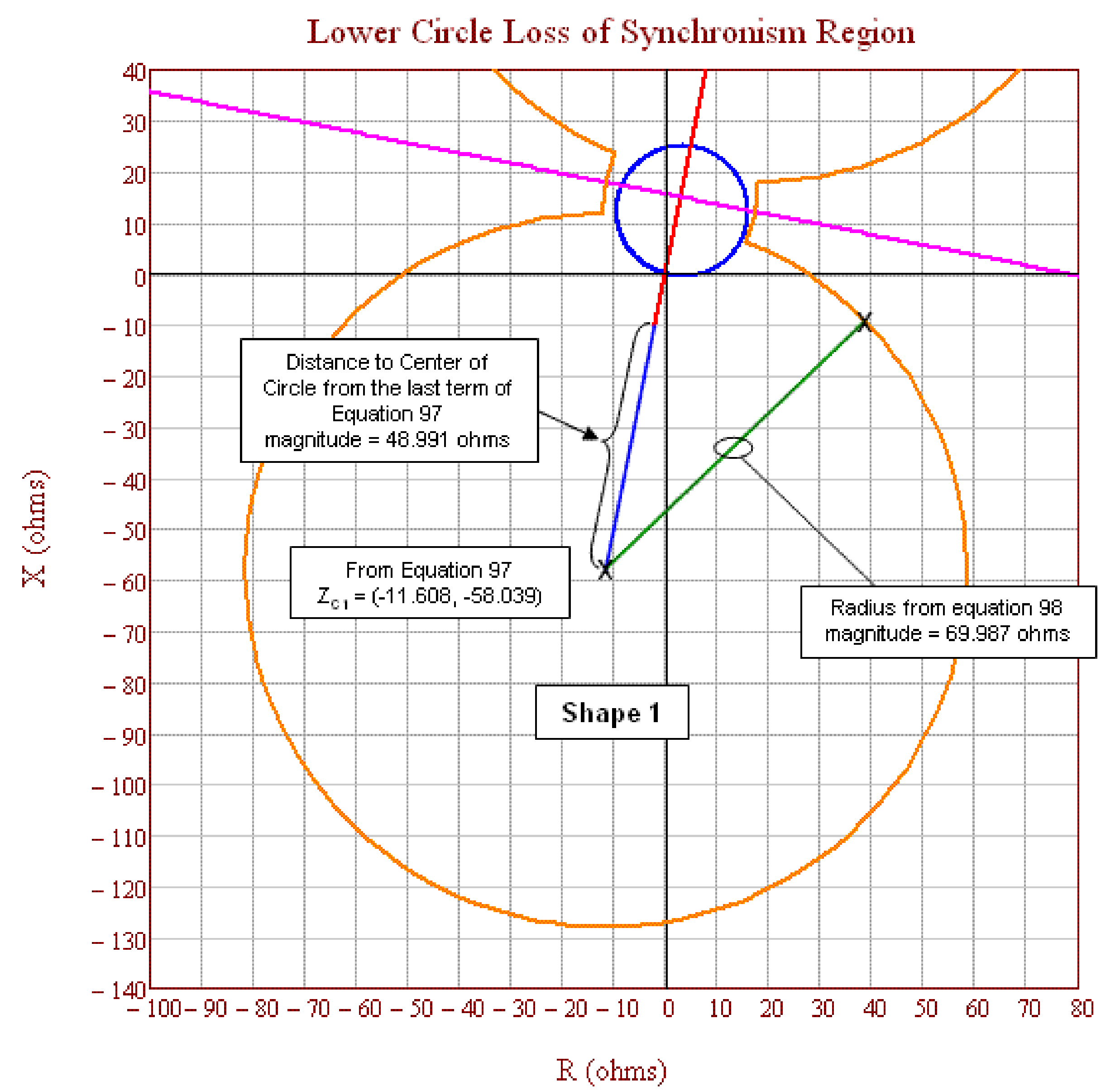


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

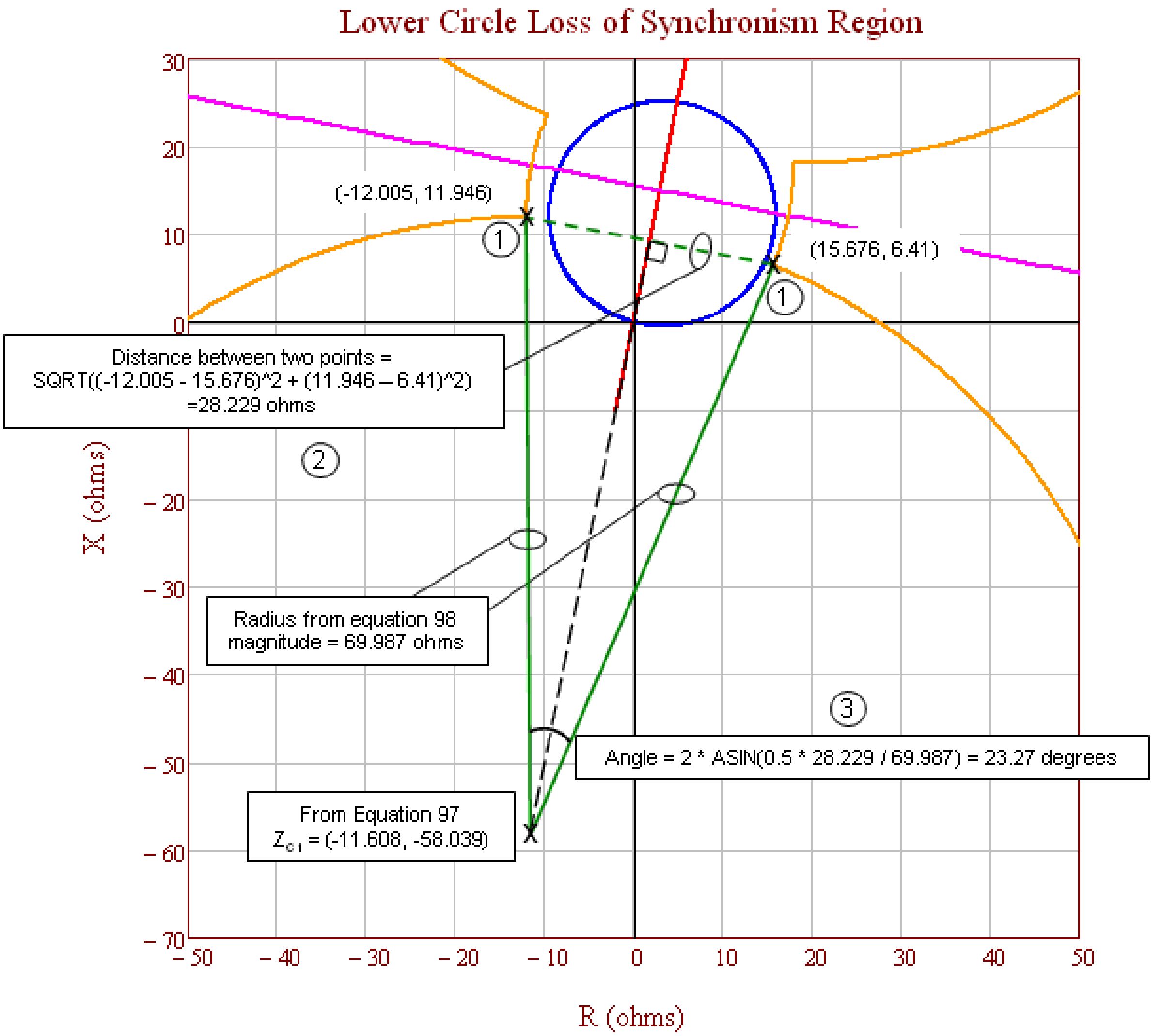


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

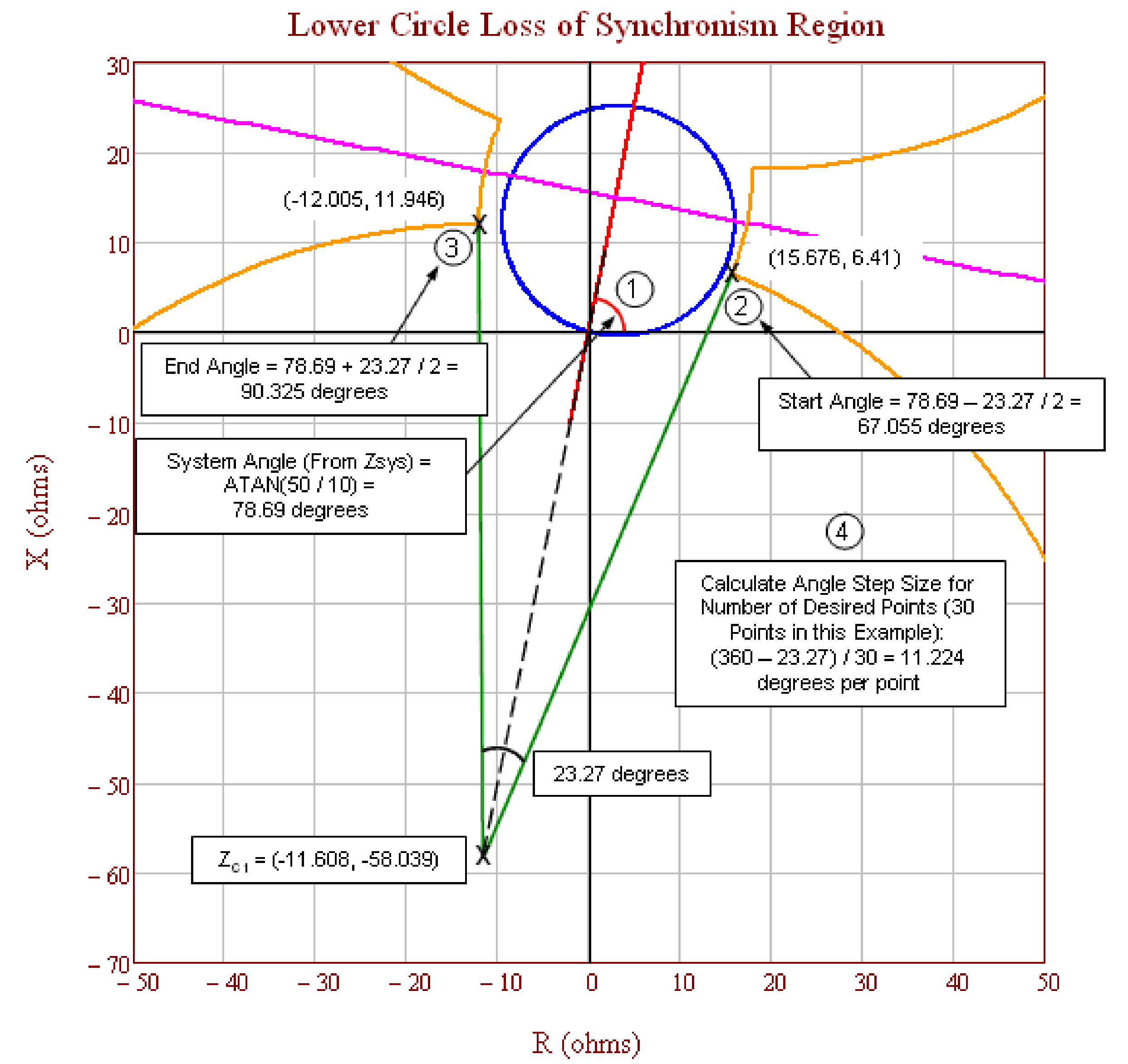


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

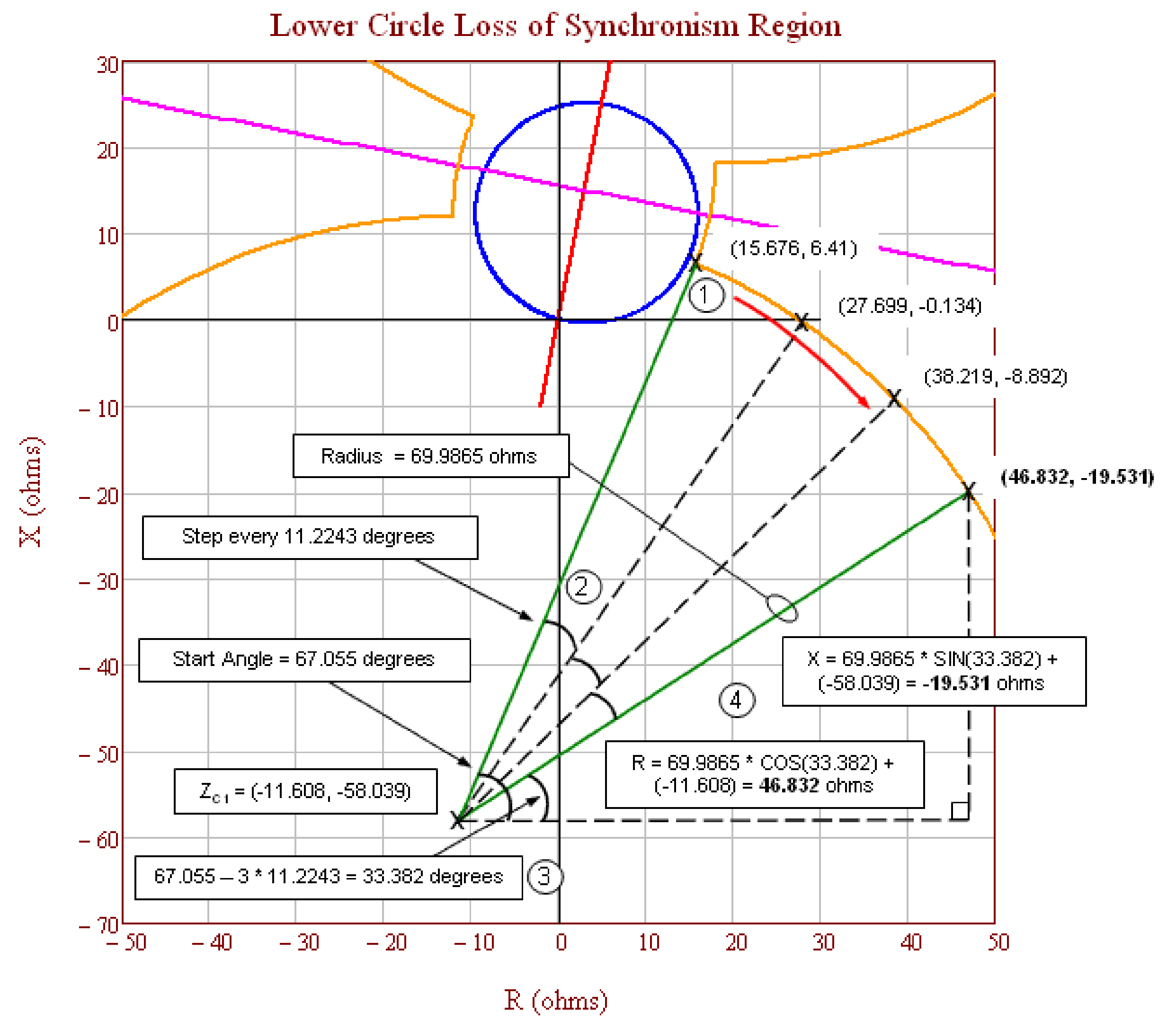


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

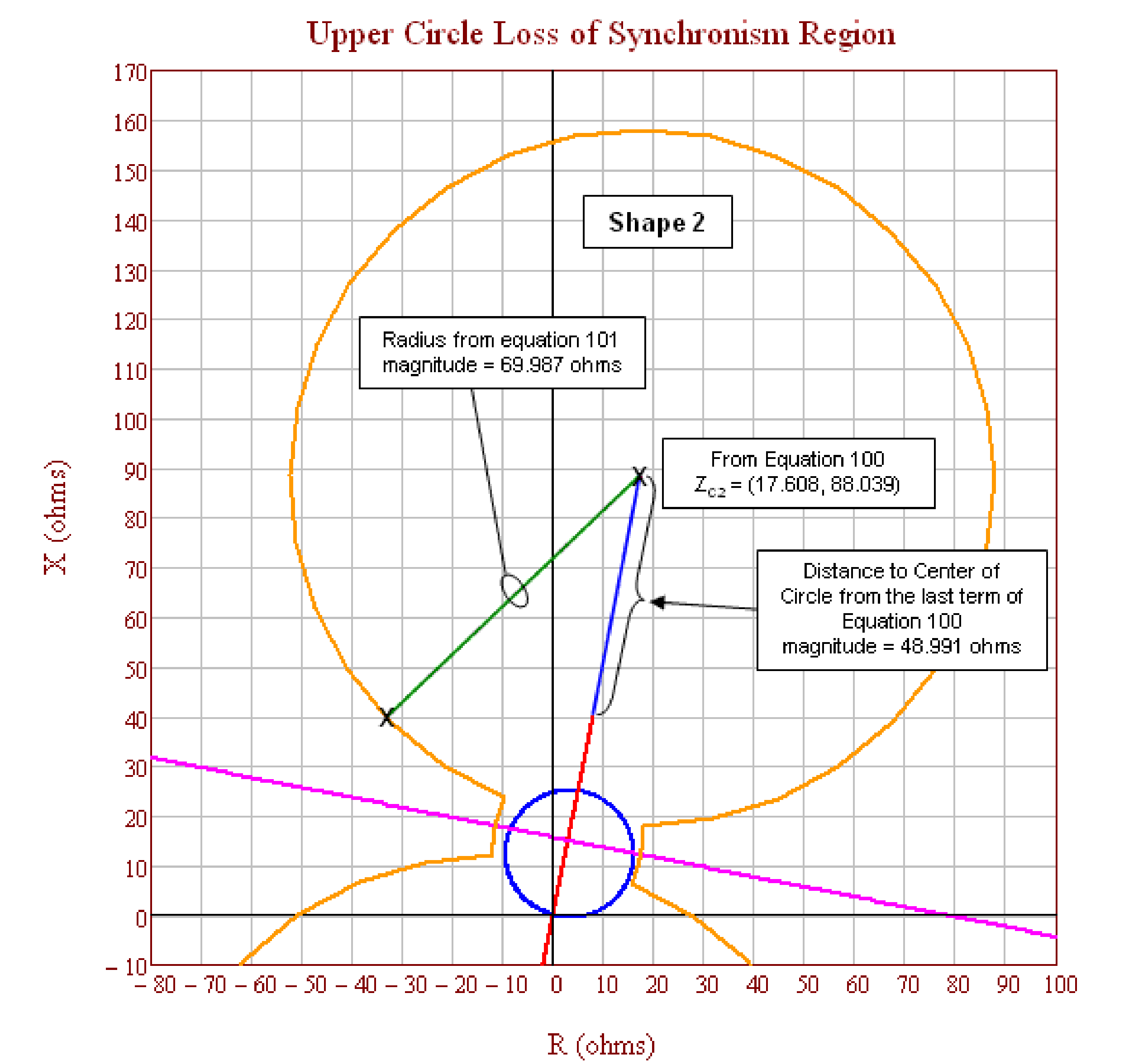


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

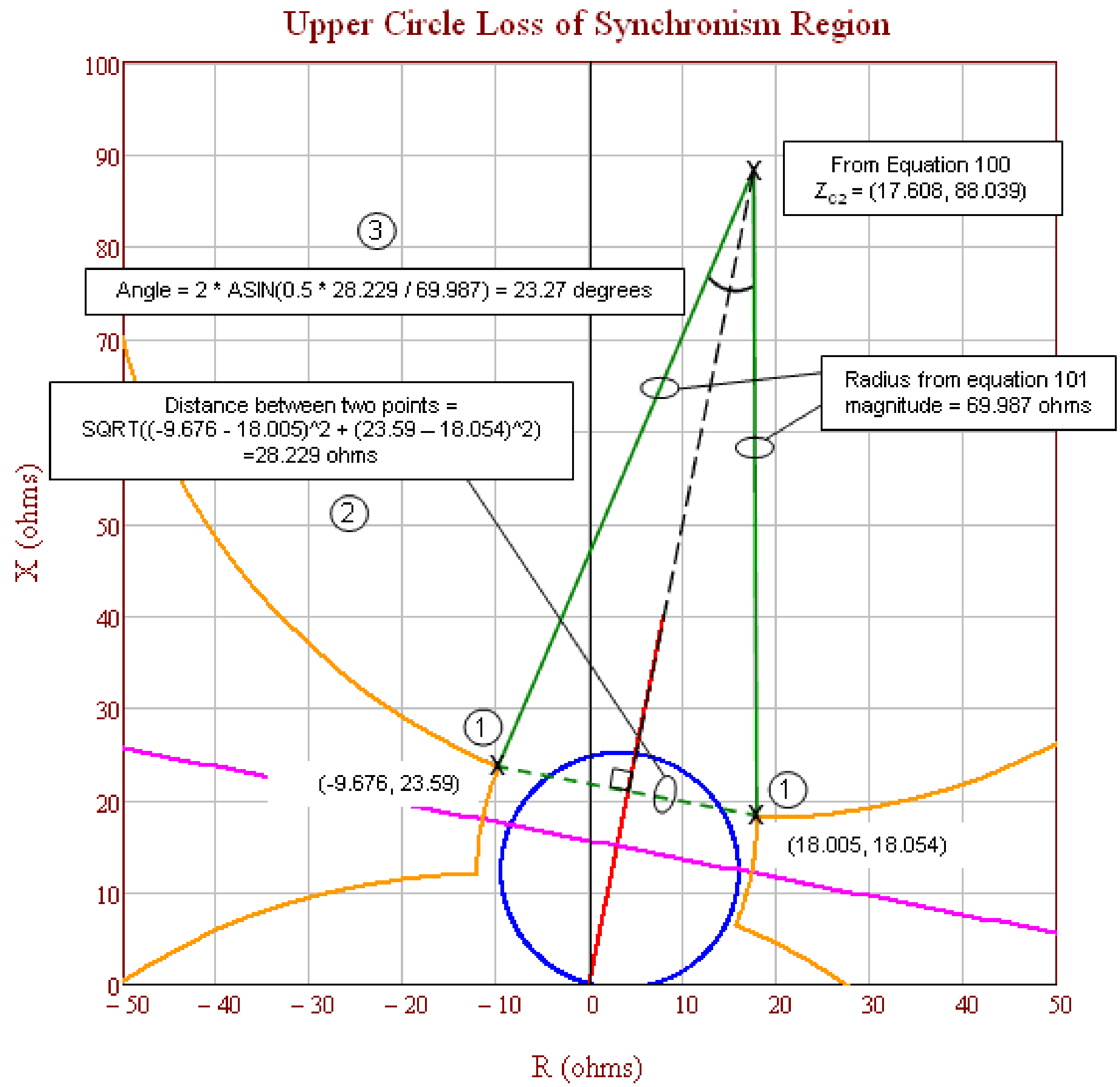


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

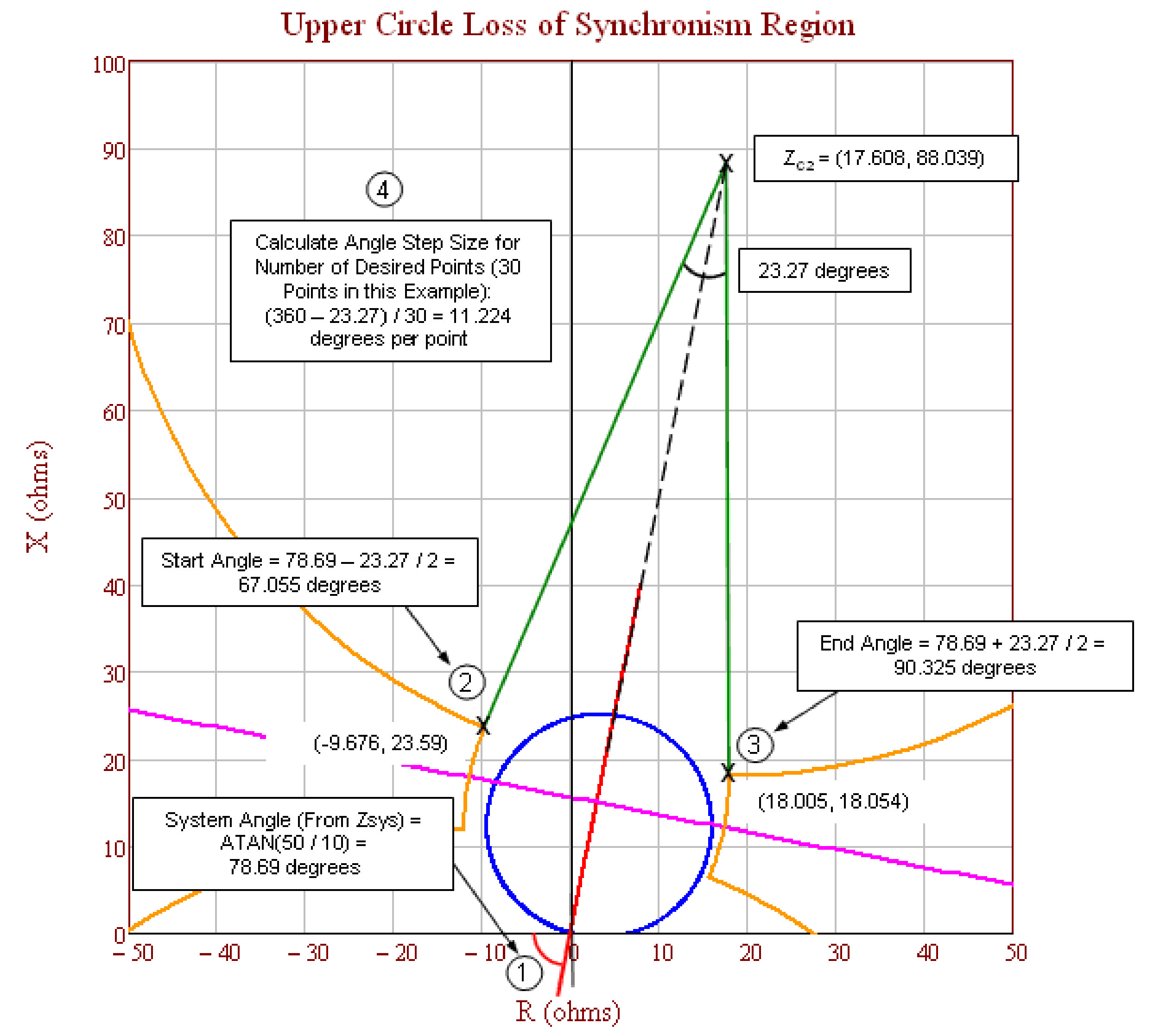


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

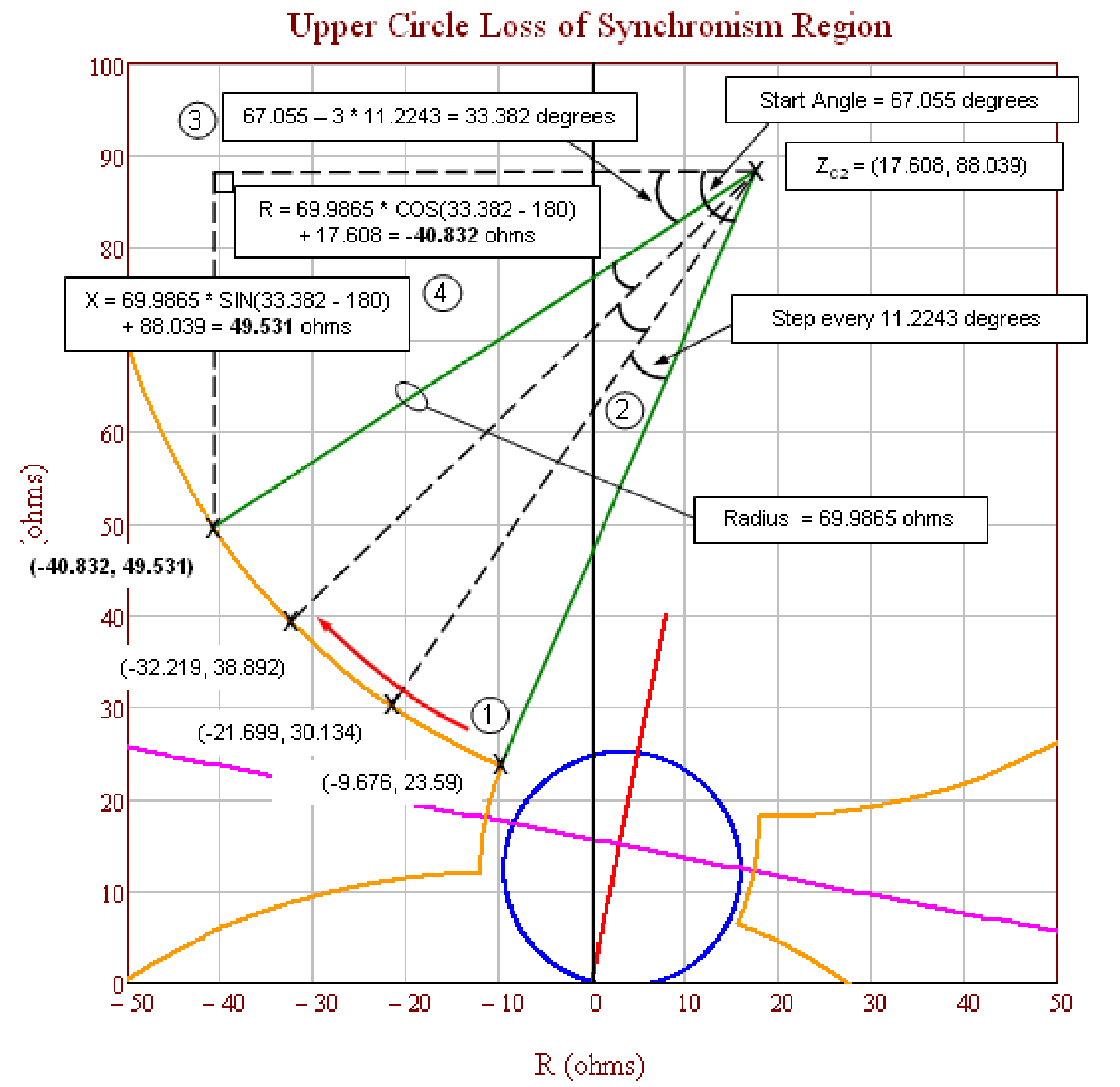


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-~~1~~ 2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-~~1~~ 2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the

maximum power transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-~~1~~ 2 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

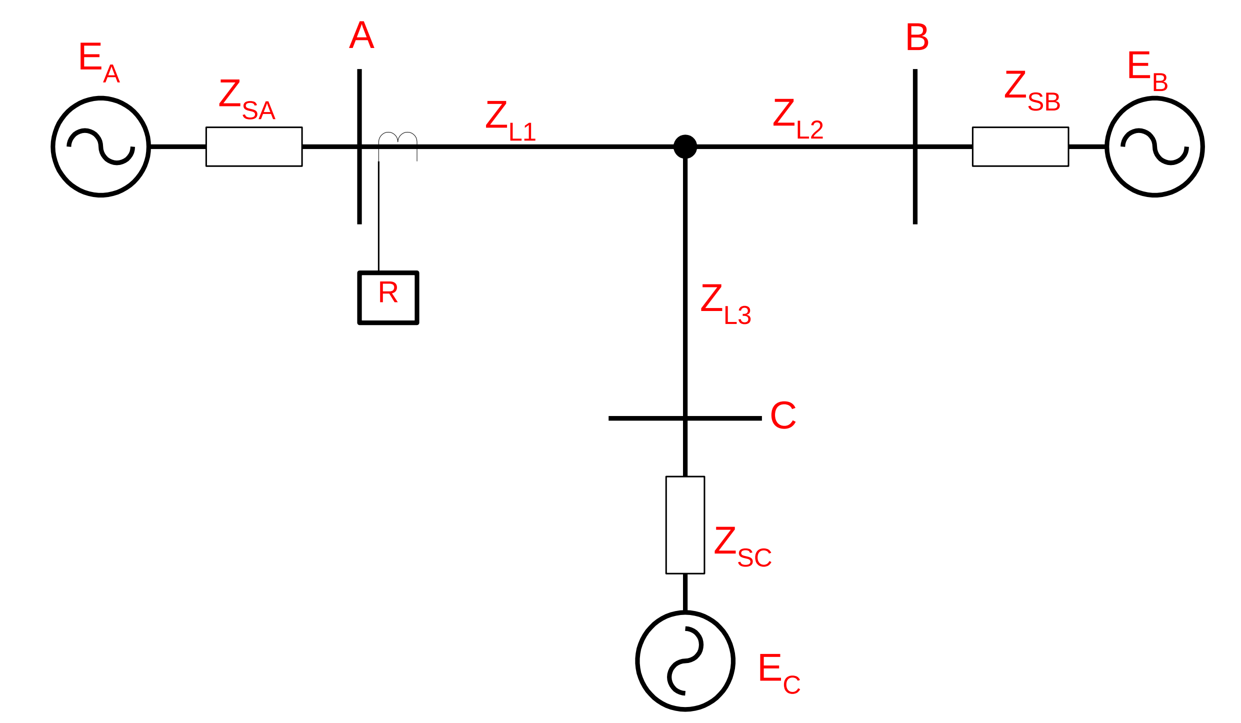


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

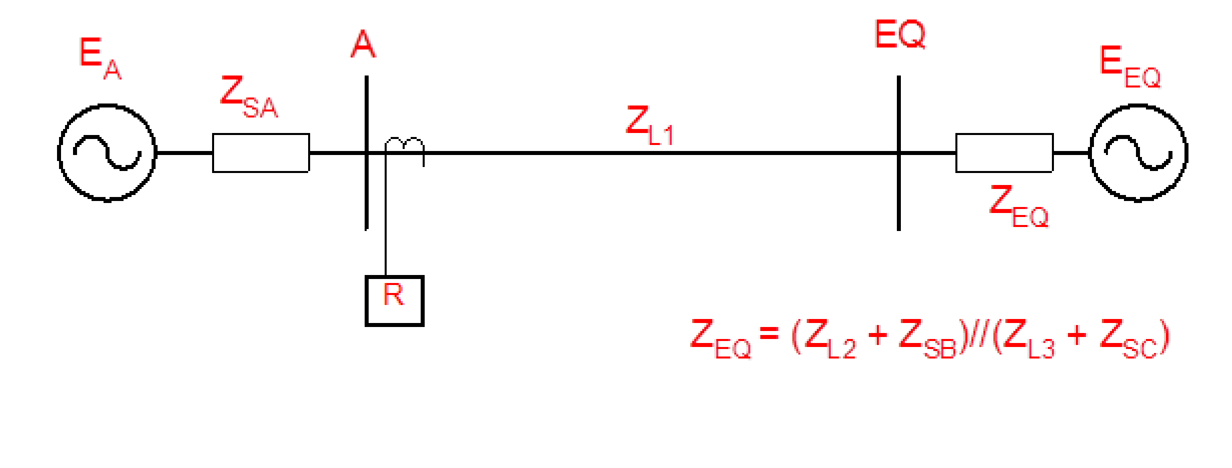


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-~~1~~2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

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[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

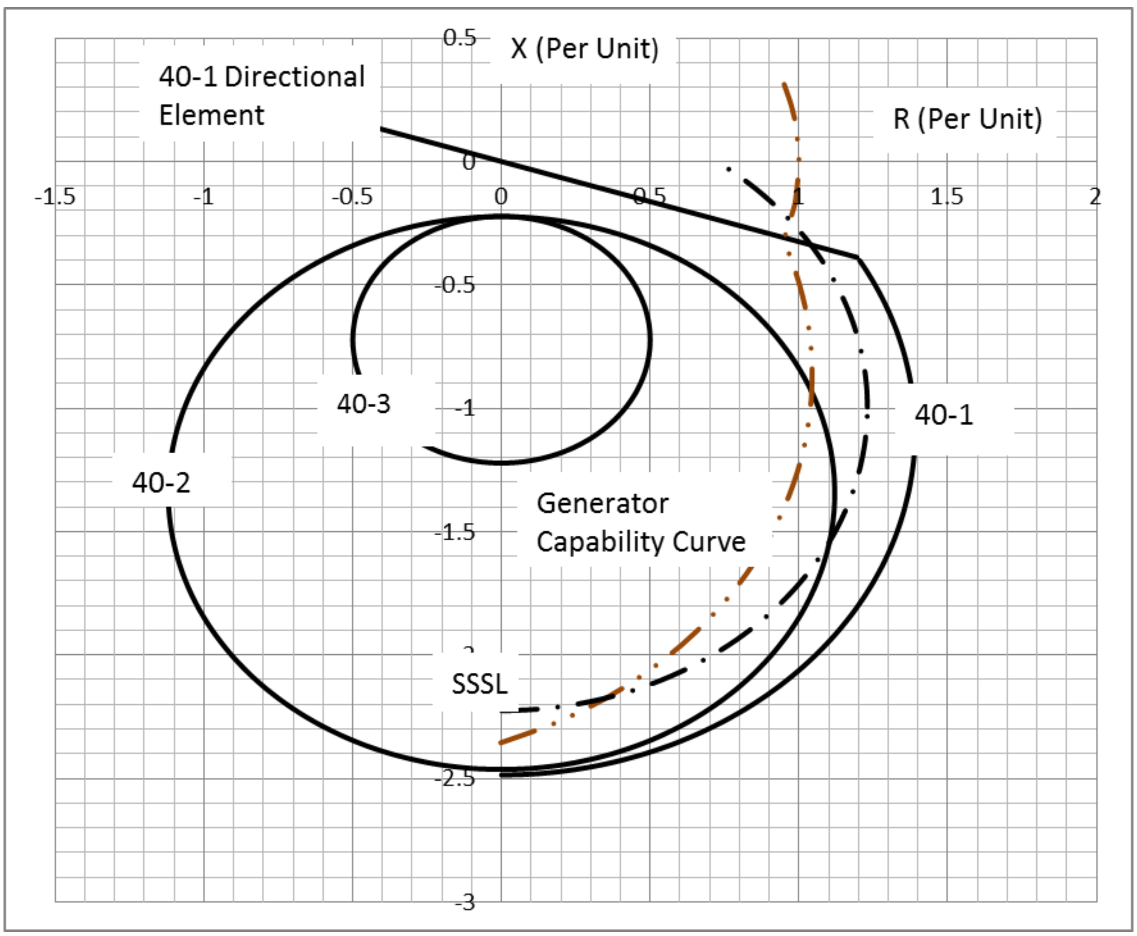

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-~~1~~2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-~~1~~ 2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

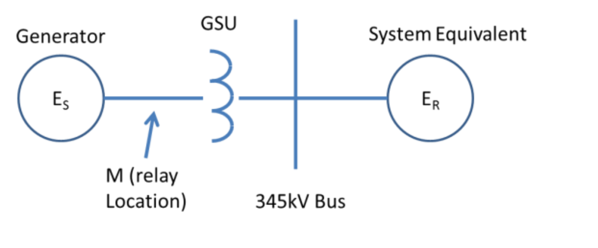

Figure 17: Simple one-line diagram of the system to be evaluated.

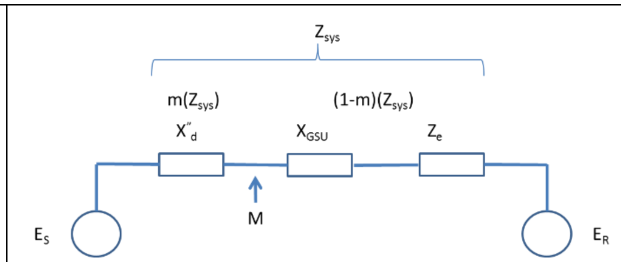

Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.						
	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-~~1~~ 2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

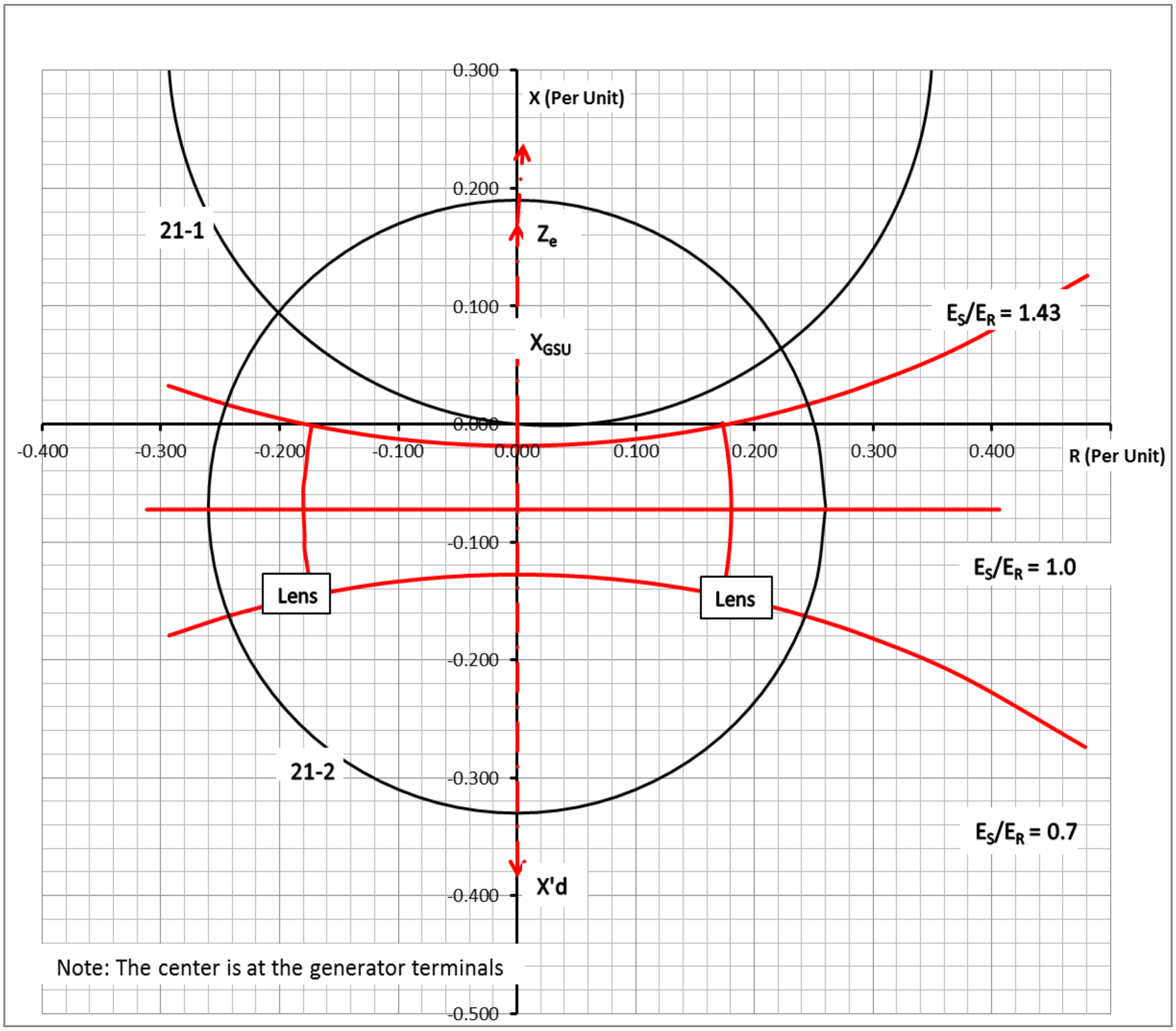

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

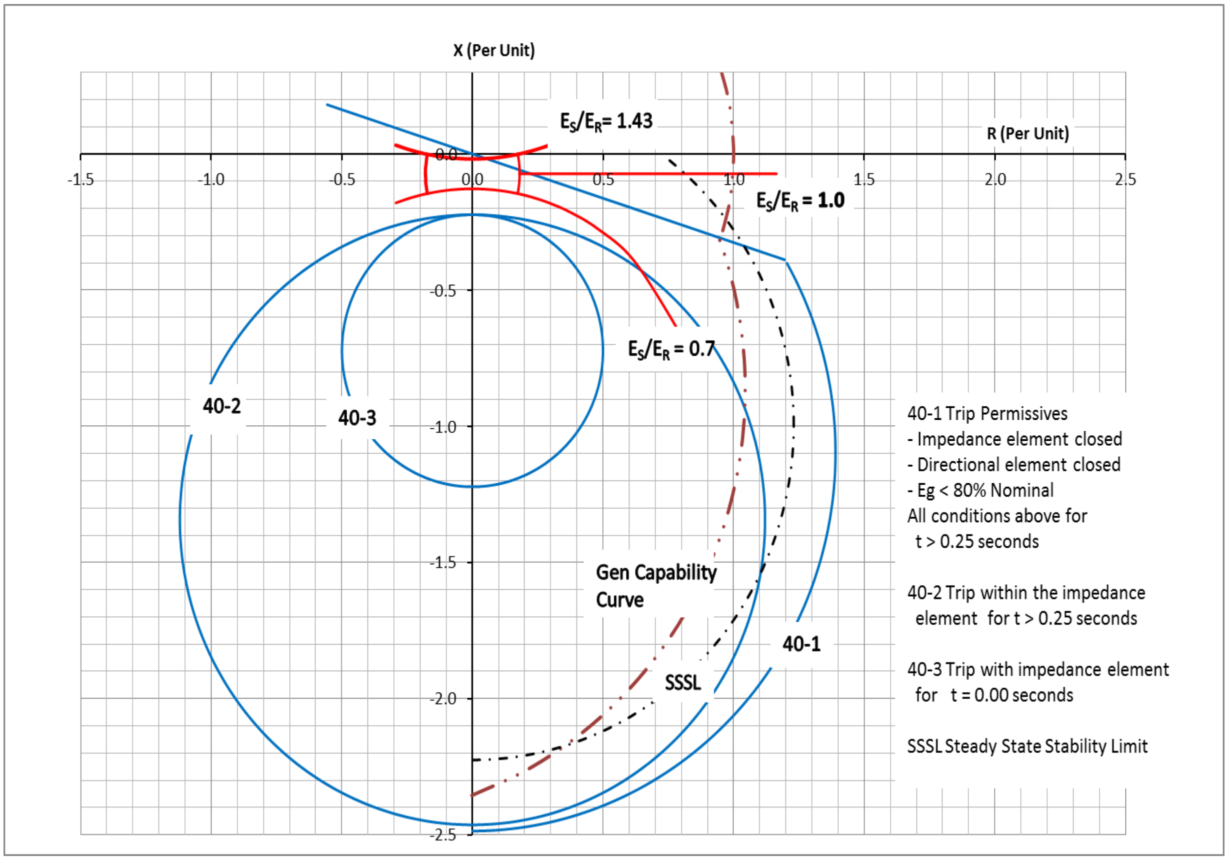

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-~~1~~2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-~~1~~2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-~~1~~ 2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d’), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

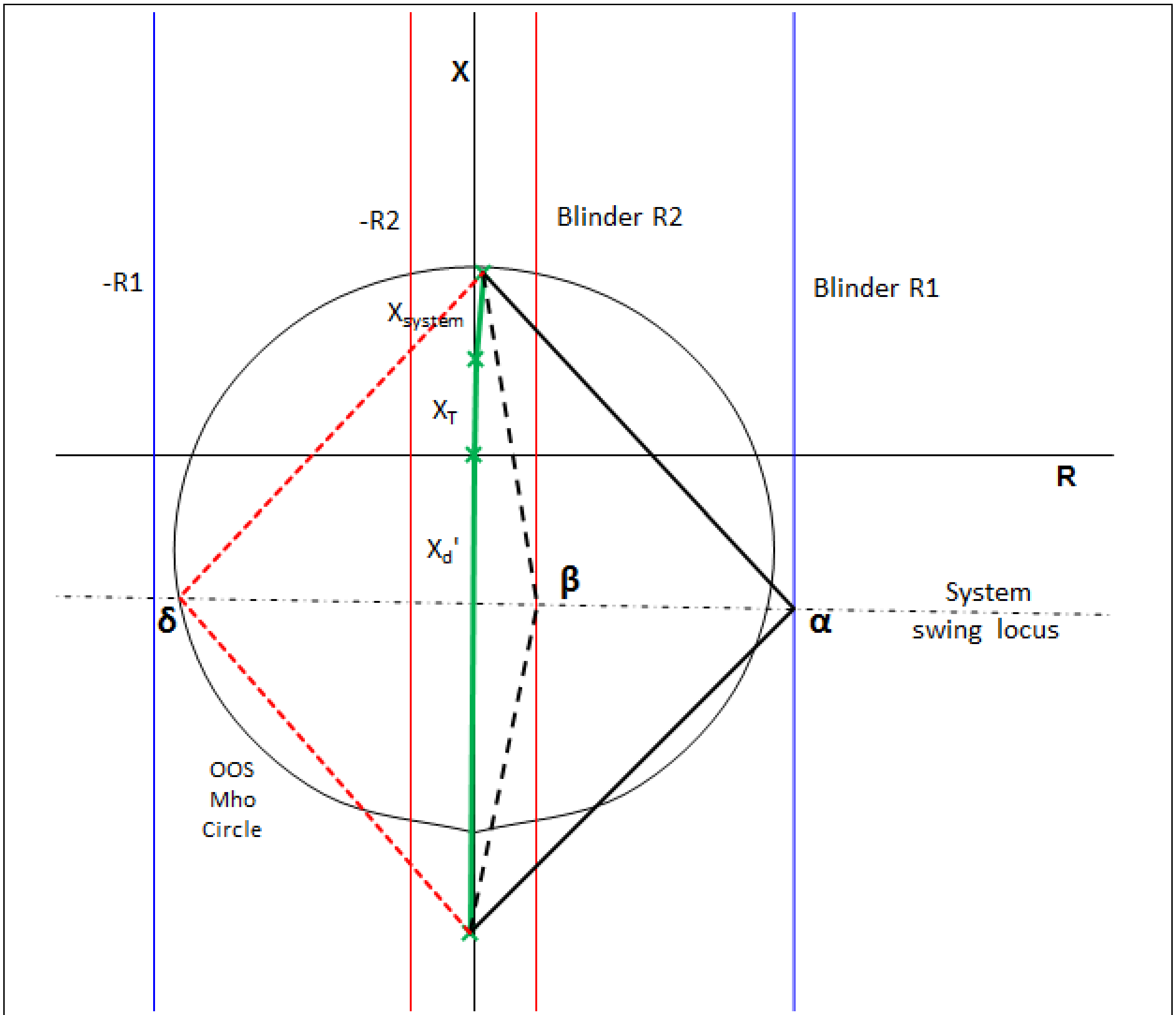

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

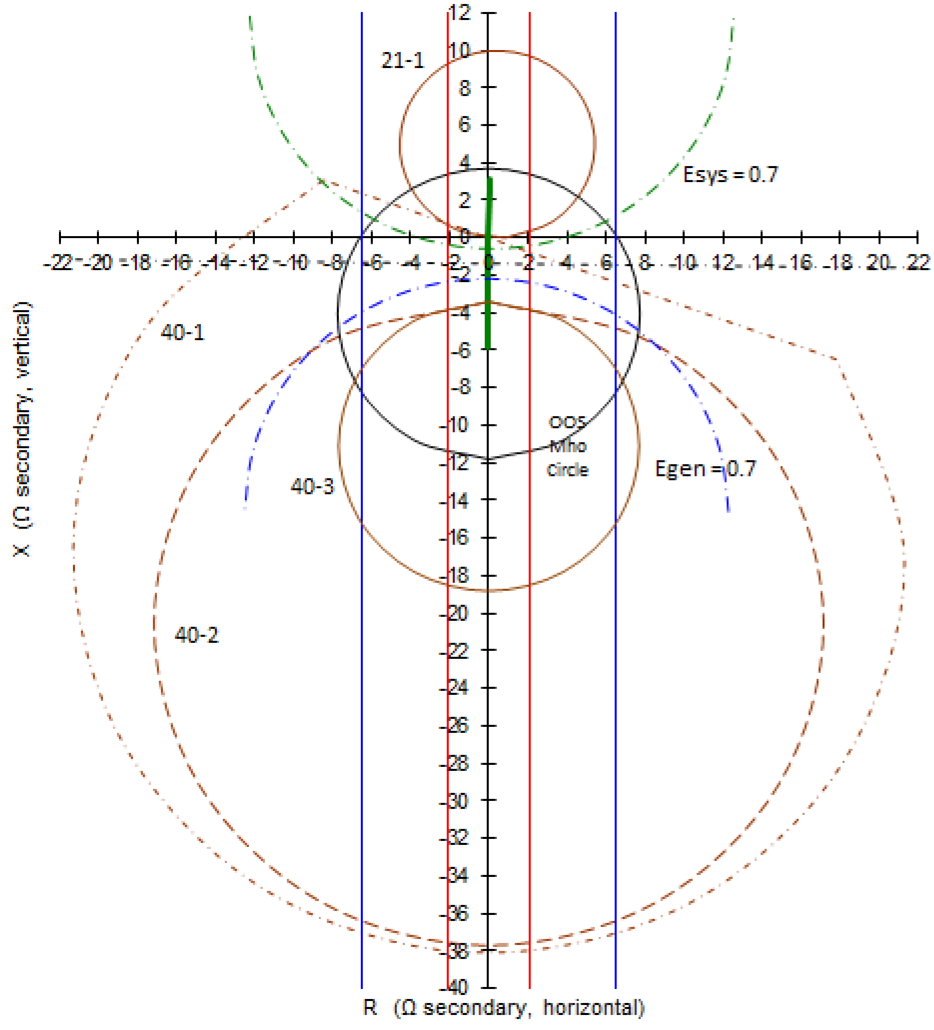

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-~~1~~2 – Attachment B criteria or can be excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-~~1~~2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-~~1~~2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-~~1~~2 – Attachment B criteria.

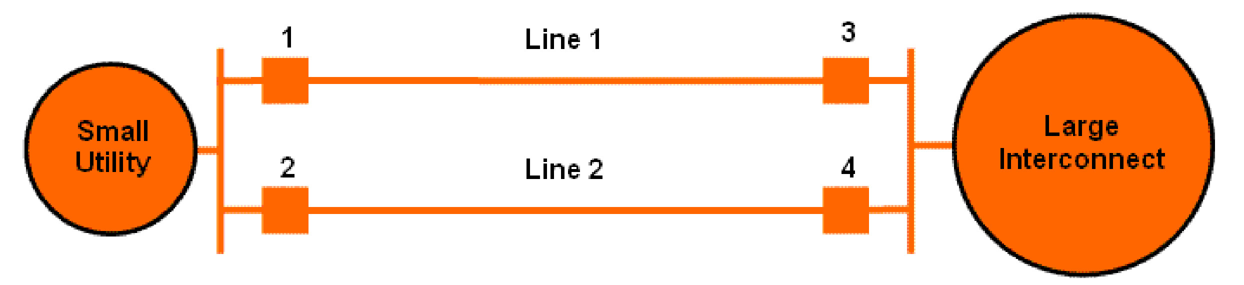

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

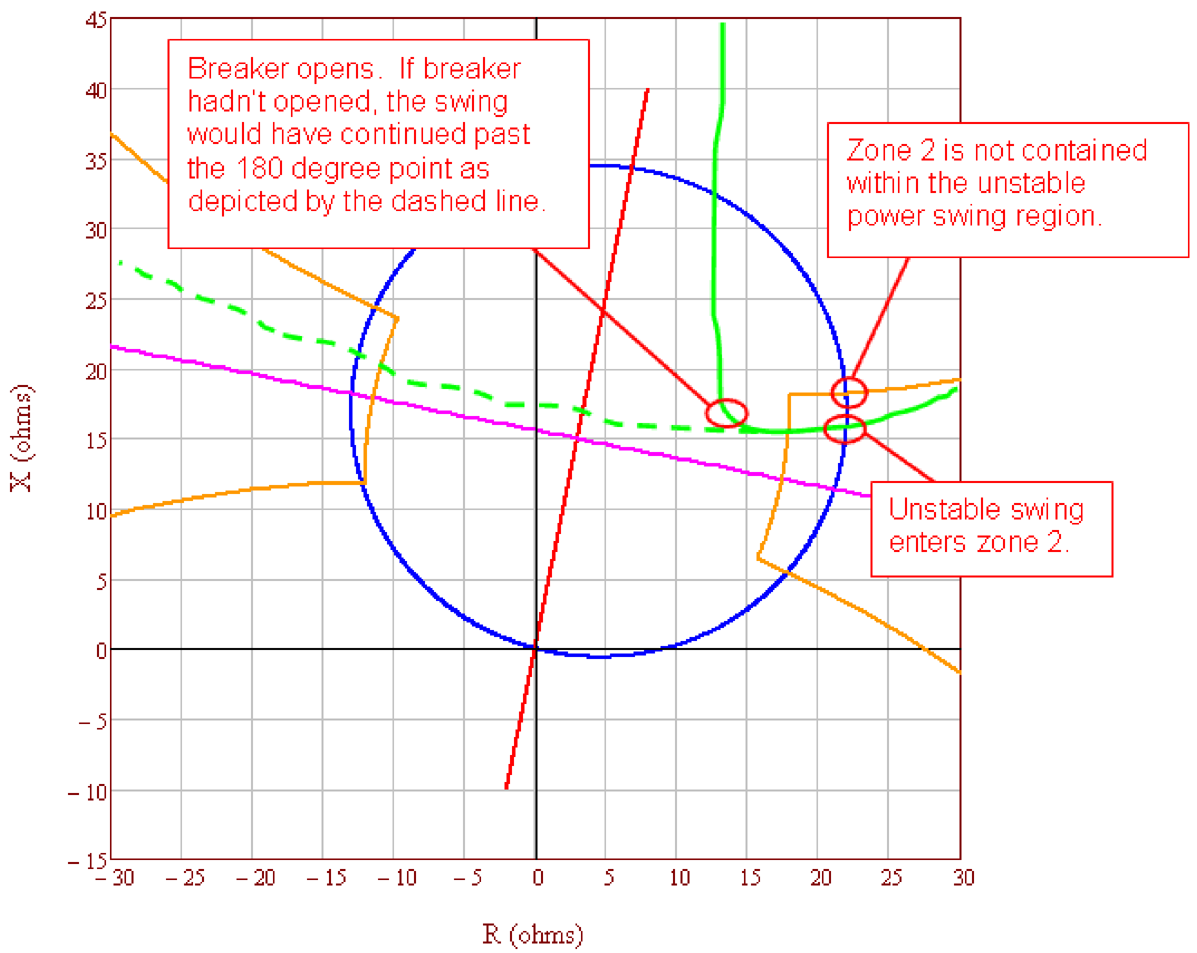

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-~~1~~2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

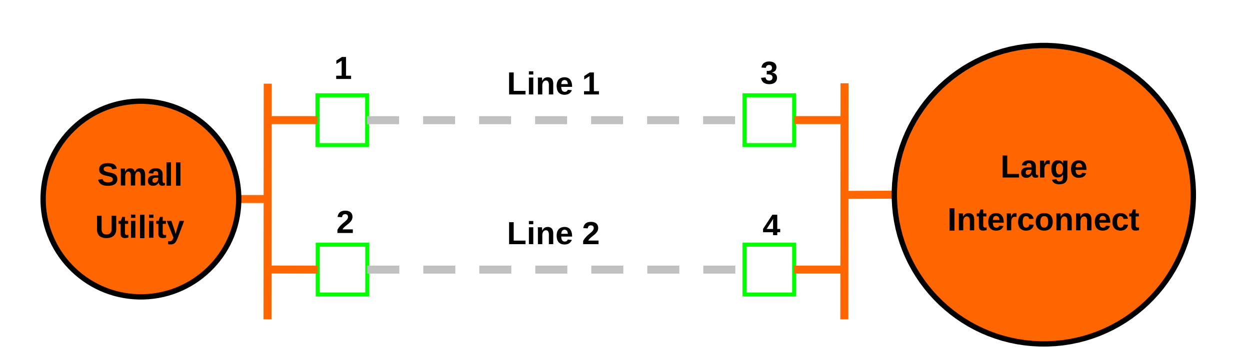

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

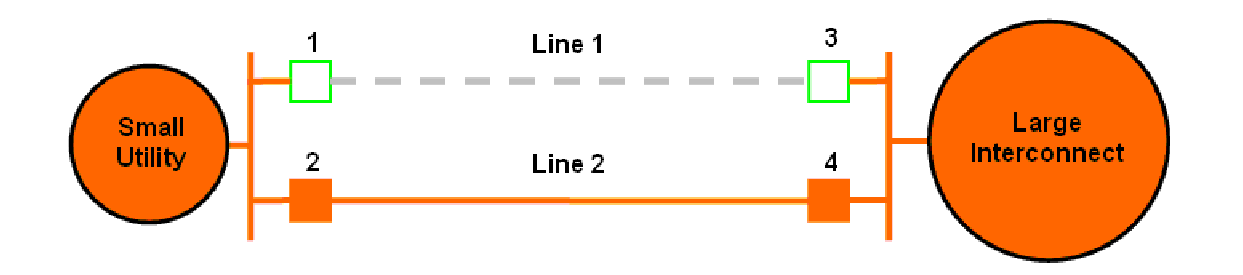

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

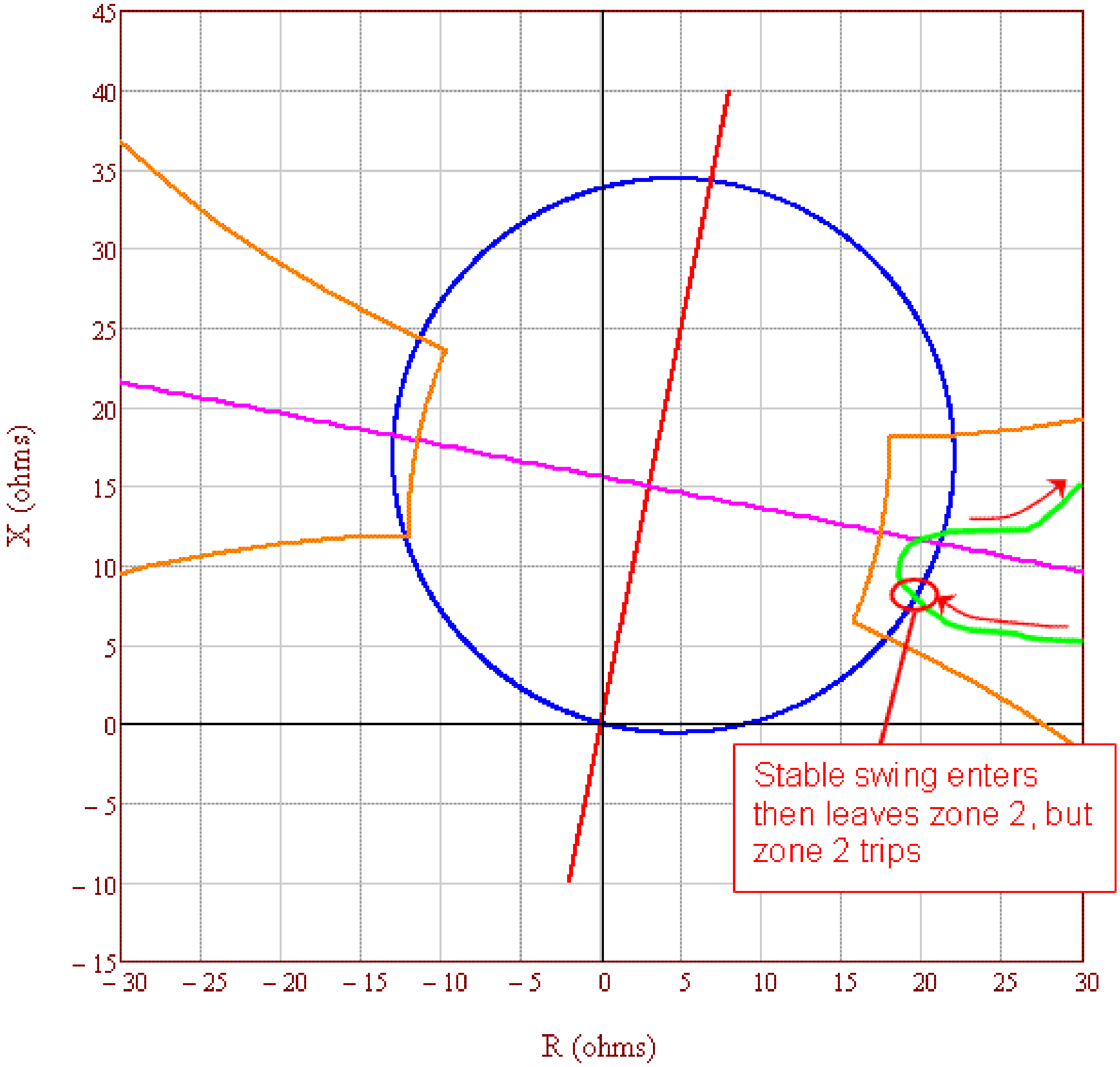

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the ~~PRC-026-1~~PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

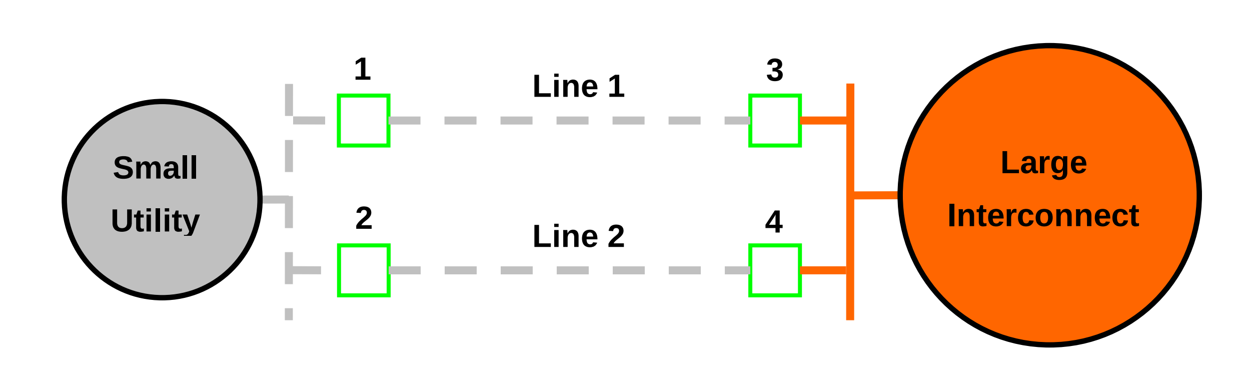

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-~~1~~2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-~~1~~2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-~~1~~2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-~~1~~2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

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Exhibit A-9

Definition of System Operating Limit
(Clean and Redline to Last Approved)

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~

~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~

~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~

~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

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Exhibit A-10

Definition of System Voltage Limit (Clean)

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

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Exhibit B

Implementation Plan

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 - Establish and Communicate System Operating Limits
- FAC-003-5 - Transmission Vegetation Management
- PRC-002-3 - Disturbance Monitoring and Reporting Requirements
- PRC-023-5 - Transmission Relay Loadability
- PRC-026-2 - Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 - Establish and Communicate System Operating Limits
- FAC-003-4 - Transmission Vegetation Management
- PRC-002-2 - Disturbance Monitoring and Reporting Requirements
- PRC-023-4 - Transmission Relay Loadability
- PRC-026-1 - Relay Performance During Stable Power Swings
- TOP-001-5 - Transmission Operations
- IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of

the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-5, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
    - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
    - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
    - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
    - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator.

- *PRC-023-4: Time Period to address new designations is retained:*
  - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- *PRC-002-3, Requirement R5*
  - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.
- *PRC-023-5*
  - Each Planning Coordinator shall conduct its first assessment under PRC-023-5 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4, whichever occurs first.
- *PRC-026-2*
  - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they must complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
  - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
  - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

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Exhibit C-1

Technical Rationale
FAC-011-4

Technical Rationale for Reliability Standard FAC-011-4

April 2021

FAC-011-4 – System Operating Limits Methodology for the Operations Horizon

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1 Part 1.1 in currently-effective FAC-011-3 requires the SOL methodology "be applicable for developing System Operating Limits (SOLs) used in the operations horizon." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1 Part 1.2 in currently-effective FAC-011-3 requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings." Facility Ratings to be used in operations as SOLs are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1 Part1.3 in currently-effective FAC-011-3 requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs." This language is preserved in Requirement R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission

Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between RCs and their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1.** Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
- **3.2.** Require that System Voltage Limits respect voltage-based Facility Ratings;
- **3.3.** Require that System Voltage Limits are greater than or equal to in-service BES relay settings for under-voltage load shedding systems and Undervoltage Load Shedding Programs;
- **3.4.** Identify the minimum allowable System Voltage Limit;
- **3.5.** Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection;

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its RC Area for voltage-based Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both maximum and minimum limits are required. Maximum limits tend to be associated with equipment/facility limitations. Minimum limits are often used to prevent phenomena associated with minimum voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of “System Voltage Limits”, both maximum and minimum, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used. The terms maximum and minimum are used through the standard, rationale and definitions with regard to voltage limits however it is common in industry to use the terms low, lowest, high and highest as synonyms for maximum and minimum and such usage is acceptable.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from maximum voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Part 3.5 requires that the SOL methodology define a method for determining common System Voltage Limits between RCs and TOPs. RC and TOPs may independently identify System Voltage Limits which if not coordinated could create reliability issues. An example could be where one TOP A chooses very wide System Voltage Limits on its equipment but TOP B could have much tighter System Voltage Limits even within the same substation. TOP A may operate equipment that are within its System Voltage Limits but cause an exceedance of TOP B’s equipment. Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL methodology shall ensure System Voltage Limits are not set at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of System damping.

Also included in Part 4.1 is language requiring the SOL methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations. Many stability tools will consider a subset of contingencies that are applicable to the area in study and are expected to produce more severe System impacts rather than every single potential contingency to set the limits conservatively while minimizing the time it takes to complete the solution, which is reflected in the phrase “applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES”. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, the SOL methodology could describe which TOP or RC has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance. Additionally, Requirement R4 Part 4.3 addresses when there is an impact to other Reliability Coordinator Areas.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL methodology. For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirement R3 Parts R3.1 and R3.4 into a single part while providing flexibility to the extent of the RC Area (including other RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation".

Requirement R5

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing

Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

5.1. Specify the following single Contingency events:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2 Part 2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3 Part 3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2 Part 2.2 and Requirement R3 Part 3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in the evaluation of post-Contingency state in OPAs and RTAs (thermal and voltage). The SOL methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. These Contingencies, if any, must be specified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Part 5.3 compliments the proposed Requirement R8 in FAC-014-3 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R5 establishes the contingency events for use in determining stability limits, in performing Operational Planning Analysis (OPAs), and in performing Real-Time Assessments (RTAs). The standard requirement is not meant to imply that all TOPs within the RC footprint must use that identical list spanning the entire RC region but may use a reduced list that at least covers the area they are responsible for the most limiting Contingencies.

Requirement R6

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met.

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 Parts 2.1 and 2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in Requirement R2 Part 2.1), the post-Contingency performance criteria (in Requirement R2 Part 2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed TOP-001-5 Requirement R25 and IRO-008-3 R7 to support reliable operations for pre- and post-Contingency operating states. TOP-001 Requirement R25 states, *"Each Transmission Operator shall use the applicable RC's SOL methodology when*

determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis." IRO-008-3 Requirement R7 states*, "Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."* The above noted requirements in TOP-001 and IRO-008 ensure that the performance framework identified in the SOL methodology is used to determine SOL exceedances consistently between the RC and its associated TOPs during Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."

FAC-011-4 Requirement R6 Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA no Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Steady state flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator may have insufficient time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow. However, as noted in the NERC SOL Whitepaper, pre-Contingency load shed may not be necessary or appropriate when assessment identifies that the impact is localized.

Requirement 6 applies only to those contingencies specified by the Reliability Coordinator for monitoring in the Transmission Operators RTA and OPA. If the Transmission Operators monitors additional contingencies beyond the subset required by the Reliability Coordinator, they are not required to meet the performance metrics in Requirement 6. As an example, if a TOP chooses to monitor loss of an entire substation as a contingency within their contingency analysis this section does not require that system performance following that event must meet these performance requirements. If the loss of a substation was not a defined contingency in the RC's SOL methodology, and no other defined contingency could cause loss of the entire substation, then the TOP could define what performance criteria, if any, to apply to this contingency. Said simply, R6 specifically applies only to the events and conditions described in R5.

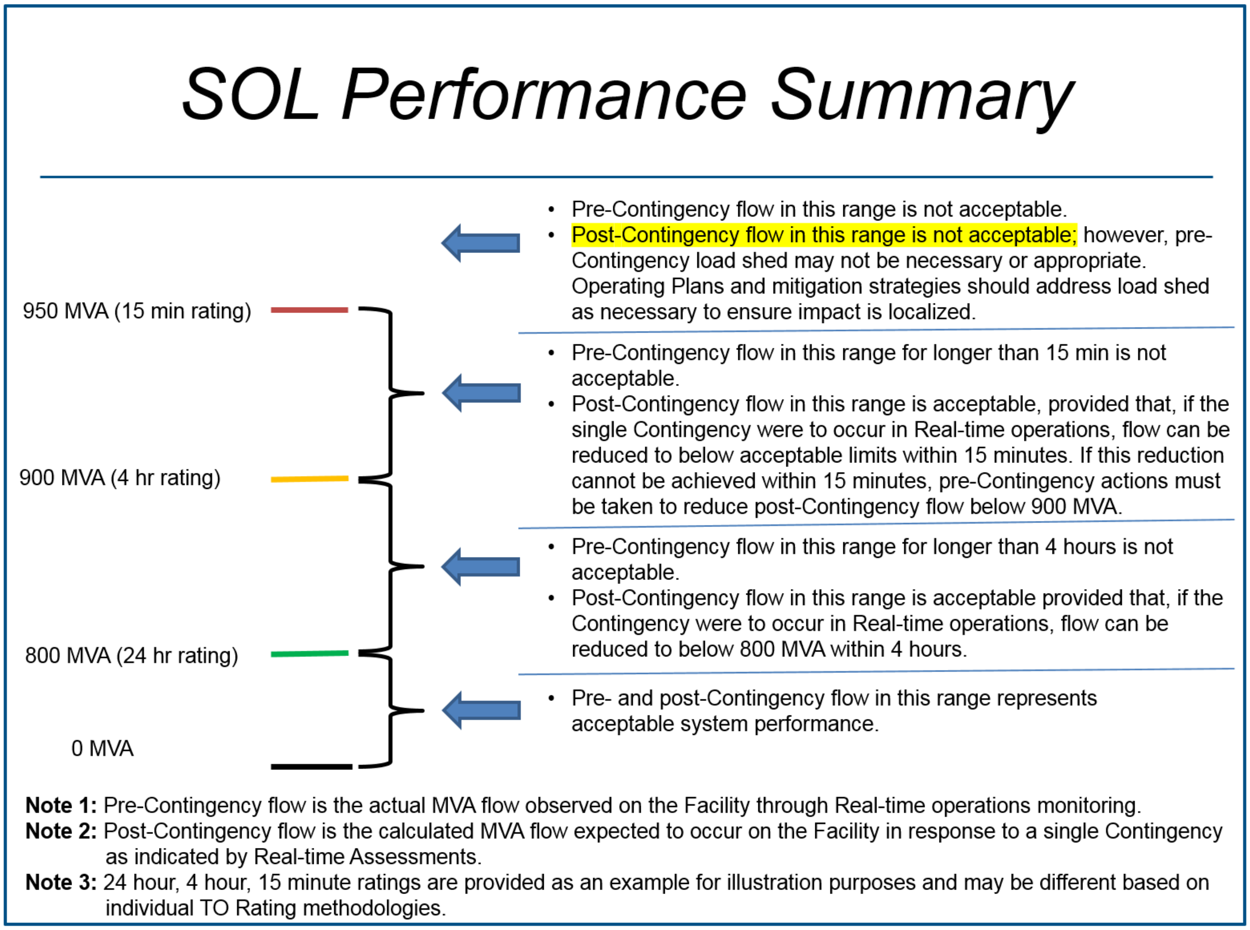

Figure 1 of the NERC SOL Whitepaper

The footnote referenced in Parts 6.1.4 and 6.2.3 states, "*Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.*" This helps to provide clarity that there are multiple methods to assessing if System performance demonstrates that Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA and Real time monitoring. Other entities may utilize tools that run at the time of the study to assess for acceptable performance or determine stability limits at the time of the OPA or RTA. Others may yet utilize other offline analysis techniques.

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5 Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation that adversely impact the reliability of the Bulk Electric System.

Part 6.4 maintains the concept identified in FAC-011-3 Requirement R2 Part 2.3.2 and intent of FERC Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Part 6.4 clarifies that load shedding as a remedy in the operating plan should only be allowed by the RC's methodology after other options are exercised without regard for financial impact. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan. This Operation Plan is developed in response to SOL exceedances identified in its Operating Planning Analysis including for contingencies identified in Requirement R5 against the transmission system under study and would apply to the Operational Planning Analysis. While those plans guide an operator's response to an event in Real-time monitoring or a Real-time Assessment, Part 6.4 would not directly apply to the actions taken by the operator in real time.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost, when the generation has a significant impact on the SOL exceedance.
- Curtailment and adjustment of Interchange regardless of economic cost, when the Curtailment or adjustment of Interchange has a significant impact on the SOL exceedance.
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Transmission re-configuration that does place more load at risk or create other unacceptable system performance issues is not required to be used prior to planned manual load shedding. As an example the reconfiguration of a looped network into a series of radial connections to avoid planned post contingency manual load shedding could be a re-configuration that puts more load at risk. In those circumstances the TOP and RC must select that option that best fits their operating conditions and Requirement R6 Part 6.4 is not intended to prescribe one approach over the other. Planned "manual" load shedding would be load shed plans, as part of an Operating Plan, and is load that would be shed as part of an Operator Instruction or taking action to shed the load in Real-time. Reconfiguration of a system in Real-time to avoid or lessen the amount of planned manual load shed or reconfiguration of a system in Real-time that creates additional "consequential" load loss is not part of "planned manual load shedding". Furthermore, the "all other available System adjustments" would apply only to those adjustments studied by the TOP or RC at the time of the Operating Planning Analysis and not to system adjustments that might be found during a post event review days or weeks later. Part 6.4 is an addition to the RC's SOL methodology and the RC can provide additional clarity as appropriate to their circumstances.

Planned manual load shedding in the context of Requirement R6 Part 6.4 is specific to what could be considered "firm" load, and would not include non-firm load, interruptible load, or any other load that has an arrangement that allows the load to be shed or interrupted when needed.

Requirement R7

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include:

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation

7.1.4. Pre-contingency SOL exceedances of Facility Ratings

7.1.5. Pre-contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits

7.2.2. Pre-contingency SOL exceedances of normal maximum System Voltage Limits.

Rationale R7

The changes in proposed FAC-011-4 help to provide clarity by requiring a performance framework for determining SOL exceedances in the RC's SOL methodology. This provides better uniformity in determining what is and isn't an SOL exceedance. This clarity may increase the instances of what is determined to be an SOL exceedance and thus increase the instances of communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirements R5 and R6) which states, "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.*"

Concerns were raised as to the effect on Real-time System Operators being required to communicate every SOL exceedance, especially those which were considered short duration SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 Requirement R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

Part 7.1 requires that the risk based approach require that "IROL exceedances, SOL exceedances of stability limits, post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation and pre-contingency SOL exceedances of Facility Ratings and pre-contingency Minimum System Voltage Limits will always be communicated”. While typically less frequent, these subset of SOL exceedances were determined to be of a higher risk and must always be communicated between TOP’s and RC’s. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Part 7.2 requires that the risk based approach require that “Post-contingency SOL exceedances of Facility Ratings and System Voltage limits and pre-contingency Normal Maximum System Voltage Limits must be communicated, if not resolved, within a timeframe identified by the RC which cannot exceed 30 minutes”. While typically more frequent, these subset of SOL exceedances were determined to be of a lower risk allow the RC to identify a timeframe which cannot exceed 30 minutes whereby if the SOL exceedance is mitigated (no longer an SOL exceedance) within the identified timeframe (e.g. 15min, 30 min, etc.), the SOL exceedance would not be required to be communicated to the TOP or RC. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Nothing prohibits an RC from requiring all or an additional subset of SOL exceedances than what is identified in Part 7.1 from being communicated. Nothing prohibits a Real-time System Operator from communicating beyond what is required or in line with other good utility practice (e.g. troubleshooting or communicating). These provisions are meant to ensure that a risk based approach can be applied to prevent low risk or after the fact communications from distracting System Operators from other higher priority tasks.

This proposed requirement is coordinated with proposed changes to TOP-001-5 Requirement R15 which states “*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator’s SOL methodology.***” and with proposed IRO-008-3 Requirements R5 and R6 which state, **“***Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator’s SOL methodology****.”* and **“***Each Reliability Coordinator shall notify****, in accordance with SOL methodology****, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.***”,** respectfully.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL methodology:

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

Rationale R8

The two IROL related requirements in FAC-011-3 were preserved under Requirement R8. Part 8.2 utilizes terminology consistent with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards by replacing “violating” with “exceeding”. It also inserts “exceeding” before the IROL to better harmonize with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards.

Requirement R9

R9. Each Reliability Coordinator shall provide its SOL methodology to:

- **9.1.** Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.
- **9.2.** Each of the following entities prior to the effective date of the SOL methodology:
  - **9.2.1.** Each adjacent Reliability Coordinator within the same Interconnection;
  - **9.2.2.** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;
  - **9.2.3.** Each Transmission Operator within its Reliability Coordinator Area; and
  - **9.2.4.** Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Rationale R9

Requirement R9 preserves the reliability objective of providing the SOL methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC’s SOL methodology.

In Requirement R9 Part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Part 9.2.2 also uses “responsible for planning” instead of “models any portion of” to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Part 9.2.4 differs from Requirement R9 Parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

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Exhibit C-2

Technical Rationale
FAC-014-3

Technical Rationale for Reliability Standard FAC-014-3

April 2021

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC's documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC's SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC. It's important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication of SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

RCs who have asynchronous connections should consider the impact of all possible transfer levels across those connections including when those connections are not available if lost by contingency or forced outage.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, Requirement R5 Part 5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required by, Requirement R4 Part 4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under , Requirement R5 Part 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need more information from the RC on related SOLs in other TOP areas within the region that could impact their derivation. Requirement R5, Parts 5.3 through 5.5, require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and 4.1.1.3 in CIP-014. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC. The SDT also felt that some known periodicity of information provision, per this requirement, seemed appropriate. After industry comment, an annual periodicity was chosen. This timeframe should allow sufficient analysis to document IROLs that will persist, and need monitoring by the RC and any necessary action by asset owners, per the CIP standards. Those IROL like conditions which may manifest in real time, due to forced outages are not appropriate for consideration until reviewed by the RC to determine if they are to be established as an IROL to prevent the condition from reoccurring, and warrant reporting per the standard.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models. Analysis of these models determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:
Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor allow the PCs nor TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement. The obvious example for such an exception is a facility where the PC / TP has assumed an upgrade which increases the Facility Rating (typically, the thermal limit) of the equipment in question.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans, or the use of ambient temperature assumptions in seasonal planning models that differ from those ambient weather assumptions used in operational analyses and monitoring in real time, may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases due to upgrade are appropriately included in future planning models. These provisions should be included in the documented technical rationale provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning

Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Existing FAC-014-2, Requirement R6 requires similar, though less detailed, information is shared by the planning with the RC. The SDT believes FAC-014-3, Requirement R7, improves upon this requirement and provides added clear and concise information to its impacted RCs and TOPs.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation that adversely impacts the reliability of the BES to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Rationale R8

This requirement was drafted to ensure the appropriate details (i.e. Facilities) regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. Impacted Transmission and Generation Owners consist of those entities who have facilities requiring notification and **does not** imply that all Transmission and Generation Owners need notification of whether they have facilities requiring notification or not. This is necessary to ensure Facility owners receive this input to identify the Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT's proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement 5.6, provides annual notifications to Facility owners from both operating and planning entities, whereas no such timely notification requirements exist in the standards today.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C-3

Technical Rationale
TOP-001-6

Technical Rationale for Reliability Standard TOP-001-6

April 2021

TOP-001-6 – Transmission Operations

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the [Project 2014-03] and [Project 2016-01] pages.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and

studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:
The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

FAC-011-4 R6 clarifies when an SOL exceedance is occurring and as such likely increases the number of SOL exceedances for some TOPs. This increased number of SOL exceedances could create an administrative burden on System Operators for entities that rely on operator logs as the primary form of evidence for compliance. This would be an unintended consequence of interaction between the new FAC-011-4 R6 and TOP-001-4 Requirement 14, which states, "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." This is because TOP-001-4 Requirement 14 treats all SOL exceedances equally and does not differentiate among them based on duration or risk to the BES.

Concerns were raised by drafting team members and observers as to the effect on Real-Time System Operators being required to log initiation of the Operating Plan for every SOL exceedance per TOP-001-4 R14, especially those which were considered short duration, low risk SOL exceedances that were actually successfully mitigated within a short-term time frame. This could distract System Operators to focus on compliance documentation during times when they should be fully committed to implementing the Operating Plan and mitigating the SOL exceedance.

The revised TOP-001-6 M14 addresses this concern by identifying examples of "other evidence" that can be utilized to support compliance which require less human intervention for capturing. Examples allowing TOPs to use other types of evidence such as system logs/records showing the SOL exceedance successfully mitigated in conjunction with Operating Plans is important because it clarifies that validation of successful SOL mitigation is the primary interest and focus of evidence. Successful SOL mitigation coupled with Operating Plans that have been prepared for utilization in the event of an SOL exceedance can demonstrate that the TOP initiated and implemented its Operating Plan. For example, providing outputs of State Estimator and/or Real-Time Contingency Analysis (with start time and end time of SOL exceedances) in conjunction with Operating Plans that outline roles and responsibilities between TOP and its RC in eliminating SOL exceedances, would document resolution of the SOL exceedance as well as the Operating Plan in use for the resolution. These should be sufficient evidence for Requirement R14 while reducing or eliminating the administrative burden on System Operators to manually generate compliance evidence via logging or recording actions.

These Operating Plans may be strengthened with clarifying information such as automatically switched or scheduled switching operating strategies/processes that describe how automatic control actions correct SOL exceedances, which can prevent unnecessary collection of evidence.   Use of operating policies as a part of Operating Plan may include specific control actions (such as taking a transmission line out of service or disconnecting a generator for a low risk high voltage SOL exceedance) on post-contingent basis, and may be utilized if it was included into operating protocols and confirmed in real-time. Other records, such as binding constraint logs, could document the actions taken to alleviate certain thermal SOL exceedances through the role of redispatch algorithms that generate revised dispatch setpoints for generators to alleviate the constraint.

Finally, further evidence may include some of the operating protocols shared between a TOP and RC as part of the Operating Plan; they may support instances where the TOP and RC agree to each take certain predetermined actions and or share information.   For example, if an RC had to initiate manual redispatch with a Generator Operator when a TOP initiated binding constraint was insufficient (e.g. not fast enough), the TOP may utilize RC-provided logs as evidence of compliance if the RC and TOP have agreed to share such information. Additionally, use of these joint operating protocols as evidence recognizes situations

and operating conditions when the RC initiates and implements an Operating Plan on behalf of TOP, per these joint operating protocols. In these situations, pre-specified actions taken by the TOP and RC and agreed upon in their joint operating protocols could allow the RC's binding constraint logs to be used by the TOP as evidence of compliance.

Rationale for Requirement R15:
Clarity of what is determined to be an SOL exceedance in new revision FAC-011-4 may increase, in some instances, the number of SOL exceedances and thus the communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirement R5 and R6) which states, "Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded."

Concerns were raised as to the effect on System Operators being required to communicate every SOL exceedance, especially those which were considered short duration, low risk, SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements of TOP-001-5 R15 with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard. This communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output to operator to operator communications.

Rationale for Requirements R16 and R17:
In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication

paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R25:
Requirement R25 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C-4

Technical Rationale
IRO-008-3

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Technical Rationale for Reliability Standard IRO-008-3

April 2021

IRO-008-3 – Reliability Coordinator Operational Analyses and Real-Time Assessments

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board of Trustees approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

Rationale for R2 and R3:
Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

Rationale for R5 and R6:
In Requirements R5 and R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications. The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other

real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard.

Rationale for R7:

Requirement R7 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C-5

Technical Rationale
System Operating Limit Definition

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3).
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2).
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3).
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2).

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with

requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts. Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.

These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO

standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the Project 2014-03 Whitepaper provided clarity on the SOL concept,

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the SDT posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use

maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase “used in Bulk Electric System operations” to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed requirement R6 in proposed Reliability Standard FAC-014-3 to address that issue.

As discussed in detail below, the SDT determined that references to “most limiting criteria” and “acceptable reliability criteria”, and the manner in which the “specified system configuration” and the “pre- and post-contingency” phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the “most limiting criteria” concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the “most limiting criteria.” Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the “most limiting criteria” concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing “most

limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

<u>Acceptable Reliability Criteria</u> – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

<u>Specified System Configuration</u> – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

<u>Pre- and Post-Contingency</u> – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

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Exhibit C-6

Technical Rationale
System Voltage Limit Definition

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for

the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

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Exhibit C-7

Technical Rationale
Exclusion of CIP Criteria Modifications

Technical Rationale for Exclusion of CIP Criteria Modifications by Project 2015-09

February 2021

Introduction

The Project 2015-09 Standard Drafting Team (SDT) is proposing the retirement of the NERC FAC-010-3 - System Operating Limits Methodology for the Planning Horizon Reliability Standard. The SDT further proposes a new construct regarding the coordination of the Planning Assessment (TPL-001-4 - Transmission System Planning Performance Requirements) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new construct consists of substantial modifications to FAC-011-3 - System Operating Limits Methodology for the Operation Horizon and FAC-014-2 - Establish and Communicate System Operating Limits. These proposals together represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to prevent instability, Cascading or uncontrolled separation that adversely impact the reliability of the BES up to and including Real-time operations.

The proposed construct does not make use of an SOL methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4, and potential conflicts with the Reliability Coordinator's (RC) SOL methodology. During their discussion of FAC-010-3's retirement, the SDT concluded (with industry concurrence) that SOLs, and Interconnection Reliability Operating Limit (IROLs), only appropriate in the operations time horizon, and should not be determined in the planning horizon.

With these proposed changes to the FAC standards, and this conclusion regarding SOLs, the SDT was tasked with ensuring supplemental modifications were made, where necessary, to other Reliability Standards that made use of or referred to planning horizon SOLs. However, CIP-002-5.1a - Cyber Security — BES Cyber System Categorization and CIP-014-2 - Physical Security are not among the modification proposals despite the references, in attachments/applicability sections, to Planning Coordinator (PC)/Transmission Planner (TP) derived IROLs for use in the planning horizon. The remainder of this document provides a rationale for the SDT's exclusion of these two standards from the overall proposed modifications that result from the proposed retirement of FAC-010-3.

CIP Requirements for PC/TP Input

CIP-002.5.1a

Reliability Standard CIP-002.5.1a includes an attachment providing criteria that characterize the level of impact of CIP assets. The attachment includes 13 criteria (2.1 through 2.13) for the medium level. The first eight (8) criteria (2.1 through 2.8) focus on sets of transmission and generation facilities.

Criterion 2.6 in Attachment 1 of the standard states:

> *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.*

Upon the retirement of FAC-010, this information would still be available from the RC via that information provided due to FAC-014 R5.6, but there would be no direct tie to PC/TP derived IROLs. The SDT does not view the retirement of FAC-010 as a potential reliability gap as it related to this criterion for the following reasons.

- The RC is currently solely responsible for determining IROLs needed for operating the BES reliably. Those IROLs exist for use by the RC and are shared with their Transmission Operators (TOPs). This does not change with the new SOL construct the SDT is proposing. In the new construct, the RC will continue to provide its IROLs to its TOPs and impacted planning entities. Additionally, the RC will provide information to the transmission and generation asset owners for their Facilities that are critical to the derivation of an IROL or its critical contingencies, at least annually. This ensures that all *"Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified … as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies"* are addressed with no gaps.

- Also in this new construct, PCs and TPs will continue to conduct their respective planning assessments in accordance with TPL-001 to identify system deficiencies and the respective Corrective Action Plans (CAPs) to address them. PCs and TPs will share with impacted RCs any information on CAPs they determine are needed to correct instances of instability found in their Planning Assessment of the Near-Term Transmission Planning Horizon (proposed FAC-014-3, Requirement R7). This provides the RC additional relevant information it needs from planning entities in its determination of SOLs, including IROLs. This ensures that all *"Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified … as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies"* include relevant input from the PC/TPs.

- Criterion 2.3 references generation Facilities identified by the PC/TP as necessary to avoid an Adverse Reliability Impact. This has significant overlap, as it relates to generation Facilities, to the Facilities that would also be identified by the RC as critical to the derivation of an IROL. It is important to note that the actual operating limit (referenced in criterion 2.6) is not the focus. Rather, the identification of the relevant generation plant is the focus; this plant, if lost or somehow compromised, could adversely impact the BES. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.

- Criterion 2.4 automatically qualifies Transmission Facilities operated at 500 kV or greater voltages to be in the medium impact category. This is regardless the reliability impact of a specific Facility that could be identified by planning studies. Since these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than lower voltage Facilities. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.
- Criterion 2.5 automatically qualifies Facilities operating between 200 kV and 499 kV based on the number of connections to other Transmission stations or substations. The basic premise in this criterion is to include “well-connected” BES substations as medium impact Facilities. Since these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than Facilities not as well connected to the System. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.
- TPL-001-4 Requirement R3 Parts 3.4 and 3.5 and Requirement R4 Parts 4.4 and 4.5 require the PC/TP to, in the annual Planning Assessment, identify and create a list of the planning and extreme events that are expected to produce “more severe System impacts.” These events may overlap those events that are critical to the derivation of an IROL. The transmission/generation owners can receive the annual Planning Assessment by request as a “functional entity with a reliability related need” per Requirement R8 of the standard.
- Proposed FAC-014-3 requires the PC/TP to annually communicate to impacted Transmission Owners and Generation Owners “their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.” This list of Facilities (for specific owners), covers all facilities the PC/TP would identify as critical to the derivation of an IROL under FAC-014-2 as it utilizes the components of the IROL definition (instability, Cascading, and uncontrolled separation that adversely impact the reliability of the Bulk Electric System) to describe the relevant Facilities as opposed to using the term itself.

In addition, the information provided by the RCs per FAC-014 R5.6 will be made available annually to the facility owners. Today there is no requirement that the information described in attachment 1 of CIP-002.5.1a be provided by any entity. FAC-014 R5.6 identifies an entity (the RC) and requires the information be submitted on regular basis (at least once annually). The annual submission requirement should address the concern noted by FERC in order 777 regarding the timeliness of CIP information provision. With an annual submission, the parties submitting the data should be able to provide the required information whether the data is created in an annual process (such as seasonal studies), or some other effort with a higher periodicity. The information recipients, the CIP asset owners, should be able to budget, plan and execute necessary projects accordingly knowing that they will receive the required information annually. If the RC deems an increased periodicity is needed, they can so act, but annual requirement set the minimum standard that all entities can use.

CIP-014-2

Reliability Standard CIP-014-2 enumerates the criteria (4.1.1.1 – 4.1.1.4) for Transmission Facilities to require physical security hardening. These criteria overlap those referenced above in CIP-002-5.1a.

Criterion 4.1.1.3 in the Applicability section of the standard states:

> *Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.*

This criterion is very similar to criterion 2.6 in CIP-002-5.1a as it relates to transmission facilities. Due to the similarities in the criteria, the same rationale stated for CIP-002-5.1a applies to CIP-014-2.

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Exhibit D-1

Mapping Document
FAC-010-3

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Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT's proposed revisions contained in FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-014-3, Requirement R7 is intended to provide a mechanism for Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL methodology. FAC-014-3, Requirement R7 addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. Therefore, this requirement focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process required in FAC-014-3 Requirement R7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don't use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement R8 requires PCs and TPs to communicate pertinent information on Corrective Action Plans (CAP) developed to address any instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon to the RC and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R7 and R8 of FAC-014-3, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL methodology (FAC-011-4). Furthermore, potentially critical stability information is communicated by planners to operators resulting an improvement in reliability by increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-014-3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).

R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1:** **Note: 'b'**	
R2.3.2. System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1:** **Note: 'e'**	
R2.4. To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1:** **Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
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	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

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	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3. Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Exhibit D-2

Mapping Document
FAC-011-4

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R8 and Part 8.1. R8. Each Reliability Coordinator shall include in its SOL methodology 8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	FAC-011-4 Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: 6.1. System performance for no Contingencies	The items in approved FAC-011-3, Requirement R2.1 and R2.2 are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposedTOP-001-6 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.4 divide system performance requirements for the no contingency state (N-0) into each of the

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	demonstrates the following: 6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.. 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System	three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in

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	adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded. 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. System performance for the single Contingencies listed in Part 5.1	Part 6.2.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate “that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.” FAC-011-4 Proposed Part 6.4 is meant to clearly identify that, in determining the System’s response to any Contingency identified in Requirement R5, planned manual load shedding is an acceptable only after all other available System adjustments have been made. TOP-001-5, Requirement R25 and IRO-008-3, Requirement R7 support FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to determine SOL

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	demonstrates the following: 6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.	exceedances in accordance with its RC's the SOL methodology.

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	6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	

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	TOP-001-6, Requirement R25. R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. . IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal	FAC-011-4, Requirement R5, Part 5.1 5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4 Requirement R5, Part 5.1.

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Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	(whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; or • single pole block, with, in a monopolar or bipolar high voltage direct current system.	FAC-011-4 Requirement R5, Part 5.1. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : <u>FAC-011-4 Requirement R4:</u> Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability;	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated

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at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	4.1.2. transient voltage response; 4.1.3. angular stability; and 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages. 4.5. Describe the level of detail that is required for the study model(s), including	in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are

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	the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. <u>TOP-002-4, Requirement R2</u>: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential	addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are

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	System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-002-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit	governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made.

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	(SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or	Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly

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	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.4 albeit with improved language for clarity. FAC-011-4 Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: R6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC

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		areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.1. Specify the following single Contingency events: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• generator; • transmission circuit; • transformer; • shunt device; • single pole block in a monopolar or bipolar high voltage direct current system. 5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any. 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-	FAC-011-4, Requirement R5, Part 5.3 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational	FAC-011-4, Requirement R5, Part 5.3 and FAC-014-3 Requirement R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-014-3, Requirement R7, the Planning Coordinator is required to identify and

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014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits. FAC-014-3 Requirement R7: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and	annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.3 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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	voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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	Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL methodology the method	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
configuration, generation dispatch and Load level	for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An*	proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"	R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement R8, Part 8.2 R8.2 Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R8, Part 8.2.
FAC-011-3, Requirement R4 and Requirement R4.1:	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4:	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	R9. Each Reliability Coordinator shall provide its SOL methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request. 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection; 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL methodology within 30 days of the request if they indicate a reliability-related need for it. 8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2. R9. Each Reliability Coordinator shall provide its SOL methodology to:	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Reliability Coordinator's Reliability Coordinator Area.	9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	within the RC Area rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area; and	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit D-3

Mapping Document
FAC-014-3

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	planning any portion of the Reliability Coordinator Area; <u>FAC-014-3 Requirement R6:</u> **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies at least once every twelve calendar months. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	1. FAC-014-3, Requirements R7 2. TPL-001-4, Requirement R8 FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. <u>TPL-001-4, Requirement **R8**:</u> **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the	PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
<u>FAC-014-2, Requirement R6</u> R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	<u>FAC-014-3, Requirement R7</u> (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

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Exhibit D-4

Mapping Document
IRO-008-3

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
IRO-008-2, Requirement R1	IRO-008-3, Requirement R1	No modifications made.
IRO-008-2, Requirement R2	IRO-008-3, Requirement R2	No modifications made.
IRO-008-2, Requirement R3	IRO-008-3, Requirement R3	No modifications made.
IRO-008-2, Requirement R4	IRO-008-3, Requirement R4	No modifications made.
IRO-008-2, Requirement R5 **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a	IRO-008-3, Requirement R5 **R5.** Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments

Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*	actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*	must be communicated and if so, with what priority. This will ensure communication consistency regarding SOL exceedances within an RC's area between the RC and its TOPs and BAs. Without the addition of this reference, there is no joint method for use by the RC and its TOPs and BAs when communicating with regard to SOL exceedances.
IRO-008-2, Requirement R6 Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor:*	IRO-008-3, Requirement R6 Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor:*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency regarding SOL exceedances

Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Medium] [Time Horizon: Same-Day Operations, Real-time Operations]	*Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*	within an RC's area between the RC and its TOPs and BAs. Without the addition of this reference, there is no joint method for use by the RC and its TOPs and BAs when communicating with regard to SOL exceedances.

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Exhibit D-5

Mapping Document
TOP-001-6

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Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R1	TOP-001-6, Requirement R1	No modifications made.
TOP-001-5, Requirement R2	TOP-001-6, Requirement R2	No modifications made.
TOP-001-5, Requirement R3	TOP-001-6, Requirement R3	No modifications made.
TOP-001-5, Requirement R4	TOP-001-6, Requirement R4	No modifications made.
TOP-001-5, Requirement R5	TOP-001-6, Requirement R5	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R6	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R7	No modifications made.
TOP-001-5, Requirement R8	TOP-001-6, Requirement R8	No modifications made.
TOP-001-5, Requirement R9	TOP-001-6, Requirement R9	No modifications made.
TOP-001-5, Requirement R10	TOP-001-6, Requirement R10	No modifications made.
TOP-001-5, Requirement R11	TOP-001-6, Requirement R11	No modifications made.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R12	TOP-001-6, Requirement R12	No modifications made.
TOP-001-5, Requirement R13	TOP-001-6, Requirement R13	No modifications made.
TOP-001-5, Requirement R14	TOP-001-6, Requirement R14	No modifications made.
TOP-001-5, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	TOP-001-6, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency on SOL exceedances within an RC's area between the RC and its TOPs. Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R16	TOP-001-6, Requirement R16	No modifications made.
TOP-001-5, Requirement R17	TOP-001-6, Requirement R17	No modifications made.
TOP-001-5, Requirement R18	TOP-001-6, Requirement R18	No modifications made.
TOP-001-5, Requirement R19	TOP-001-6, Requirement R19	No modifications made.
TOP-001-5, Requirement R20	TOP-001-6, Requirement R20	No modifications made.
TOP-001-5, Requirement R21	TOP-001-6, Requirement R21	No modifications made.
TOP-001-5, Requirement R22	TOP-001-6, Requirement R22	No modifications made.
TOP-001-5, Requirement R23	TOP-001-6, Requirement R23	No modifications made.
TOP-001-5, Requirement R24	TOP-001-6, Requirement R24	No modifications made.

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Exhibit E

Whitepaper on System Operating Limit Definition and Exceedance Clarification

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
The approved definition of SOL as defined in the NERC Glossary of Terms is:

> *The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
> - *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
> - *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
> - *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The concept of SOL determination is not complete without looking at the associated NERC FAC standards approved FAC-008-3, proposed FAC-011-4, and proposed FAC-014-3 and related TOP and IRO standards (proposed TOP-001-6 and IRO-008-3):

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Ratings methodology and to establish Facility Ratings consistent with that methodology that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed are required to include, as a minimum, both Normal and Emergency (short-

term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal Rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Emergency Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of proposed FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:
   a. Requirement R2 requires that the Reliability Coordinator's SOL methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.
   b. Requirement R3 requires that the Reliability Coordinator's SOL methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.
   c. Requirement R4 requires that the Reliability Coordinator's SOL methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements.

3. Proposed FAC-011-4 requirement R6 contains the minimum framework for SOL exceedance determination to be used in the TOP and IRO standards. Specifically, requirement R6 requires the Reliability Coordinator's SOL methodology to include, at a minimum, the following Bulk Electric System performance framework:
   a. Part 6.1: System performance for no Contingencies demonstrates the following:

      Part 6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

      Part 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

      Part 6.1.3. Predetermined stability limits are not exceeded.

      Part 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

a. Part 6.2: System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

   i. Part 6.2.1: Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

   ii. Part 6.2.2: Steady state post-Contingency voltages are within emergency System Voltage Limits.

   iii. Part 6.2.3: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

   iv. Part 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1]

b. Part 6.3: System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

c. Part 6.4: In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

4. Proposed FAC-014-3, Requirement R2 requires that Transmission Operators establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
5. Proposed TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 require Transmission Operators and Reliability Coordinators, respectively, to use the Reliability Coordinator's SOL methodology when performing Real-time Assessments, Real-time monitoring, and Operational Planning Analyses to determine SOL exceedances. The SOL exceedance framework is included in the SOL methodology via the proposed FAC-011-4 requirement R6 (above).
6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all Facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into operations studies.

Some have interpreted the language in previous versions of FAC-011 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in FAC-011, with the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in FAC-011 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within FAC-011, which is both:

1. To know the Facility Ratings, voltage limits, transient stability criteria, and voltage Stability criteria, and

2. To ensure that they are all observed in assessments of both the pre- and post-Contingency state when performing Operational Planning Analyses (OPA), Real-time Assessments (RTA), and Real-time monitoring.

It is important to understand the intent behind the language “the pre- and post-contingency state.” The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. In Real-time operations, any of these types of limits can be the most restrictive limit at any point in time in the pre- or post-Contingency state. For example, if an area or Facility of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of thermal Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, a primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. How an entity accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility

Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.

2. **System Voltage Limits:**
   In the pre-Contingency and post-Contingency state, operate within normal System Voltage Limits and emergency System Voltage Limits, as applicable, within their associated time parameters.

3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC's SOL methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage response, angular stability, and System damping. Part 4.2 requires stability limits to be established to meet these prescribed stability performance criteria. For example, a study might indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

   Transient Stability Limits:
   Transmission Operators establish transient Stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or loading level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

   Voltage Stability Limits:
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the proposed FAC and the proposed and approved TOP and IRO standards, as well as the use of defined terms contained within those standards such as OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance.

Specifically,

1. FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe a performance framework for the pre- and post-Contingency state (proposed FAC-011-4 requirement R6) for SOL exceedance determinations.
2. TOP-001-6, Requirement R13 requires that each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. TOP-001-6, Requirement R25 requires that each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.
4. TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
5. TOP-001-6, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.
6. IRO-008-3, Requirement R7 requires that each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

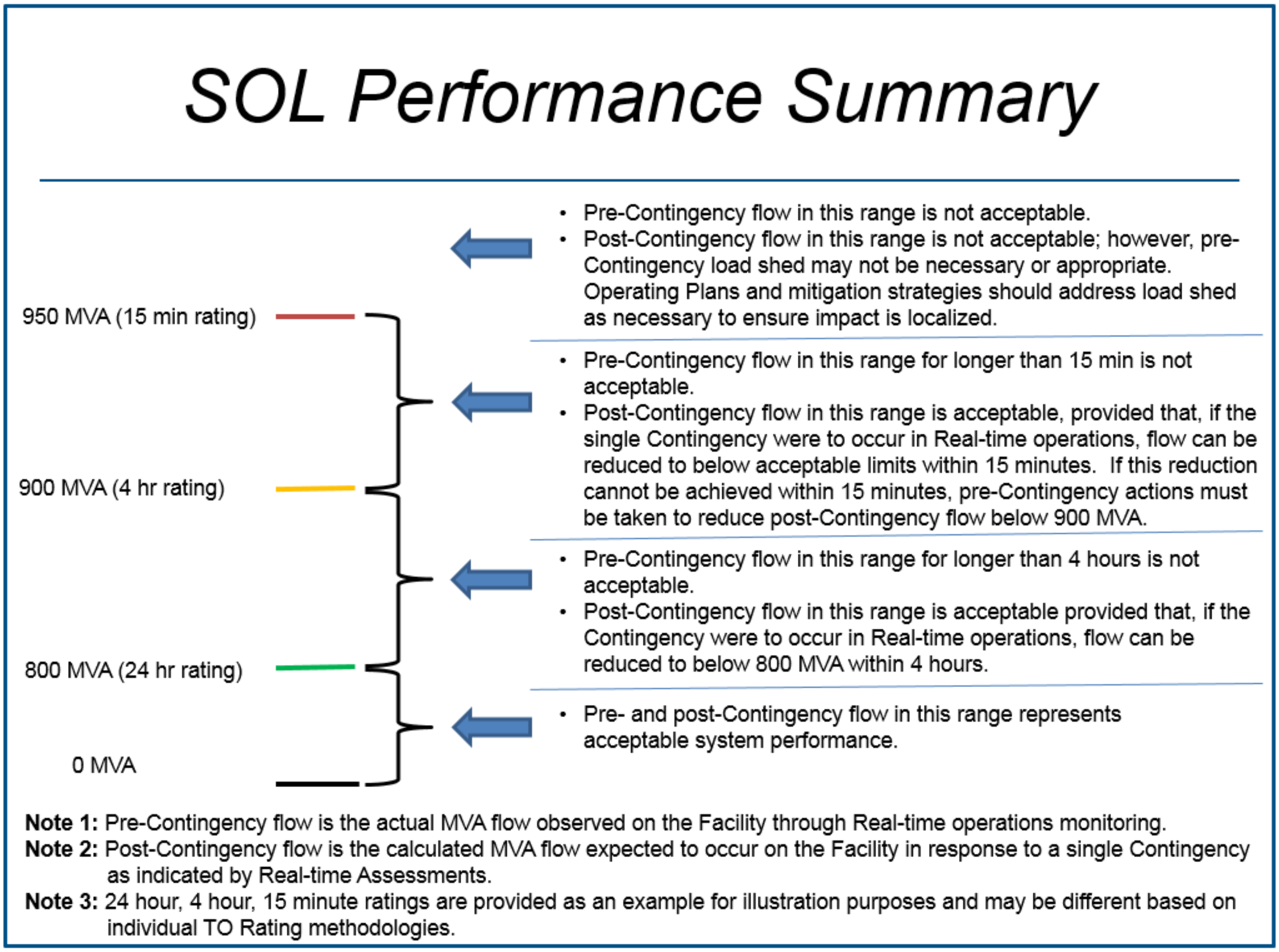

Figure 1. Facility Rating System Operating Limit Performance Summary

The following example scenarios describe appropriate operator action with respect to Figure 1:

1. **<u>Example 1 Scenario</u>** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) It is important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating if actions were available to be taken.

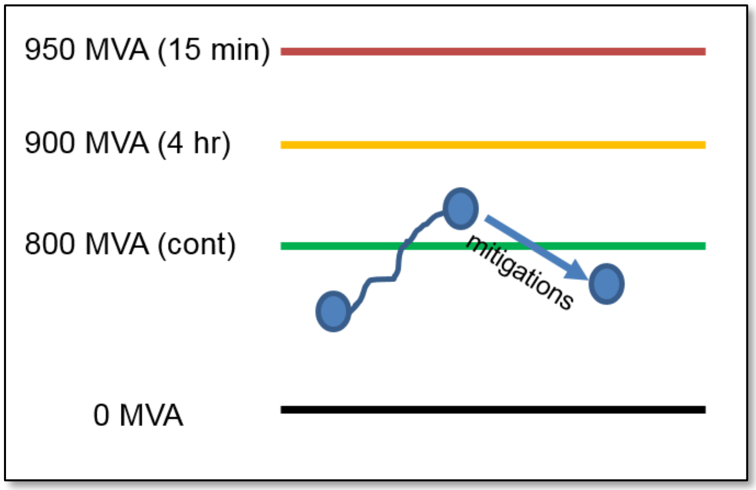

Figure 2. Example 1 Scenario – Pre-Contingency State

2. **Example 2 Scenario** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 stable.

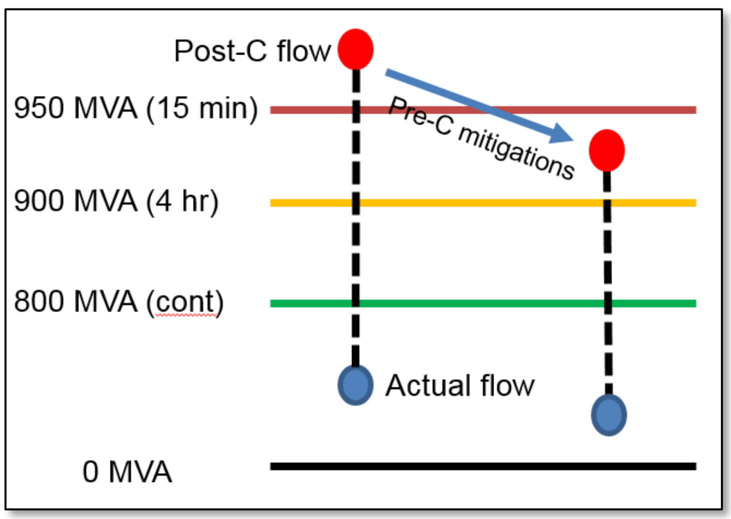

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **Example 3 Scenario** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending on how the line is rated based on the Transmission Owner's Facility Ratings methodology. If this information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating

Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

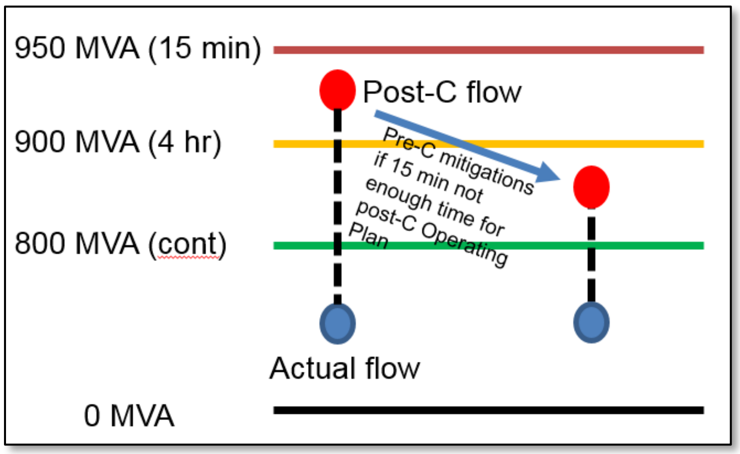

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **<u>Example 4 Scenario</u>** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

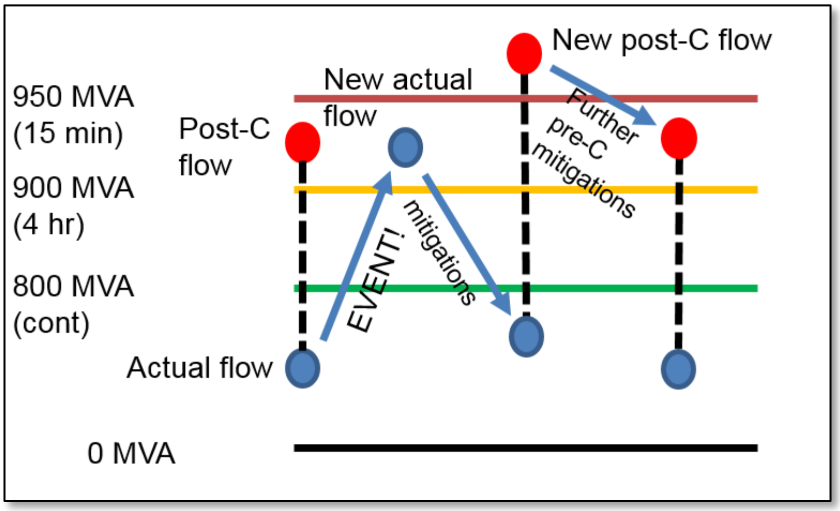

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

Steady State Voltage Limit Exceedance

SOL performance for System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency System Voltage Limits are required to be established by the TOP in accordance with the RC's SOL methodology. FAC-011-4 Requirement R3 requires that the RC's SOL methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings methodology per approved FAC-008-3.

Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL methodology. Real-time Assessments should recognize the impact of automatically controlled reactive devices and whether or not those devices are sufficient without manual operator action for maintaining voltages within System Voltage Limits pre- or post-Contingency.

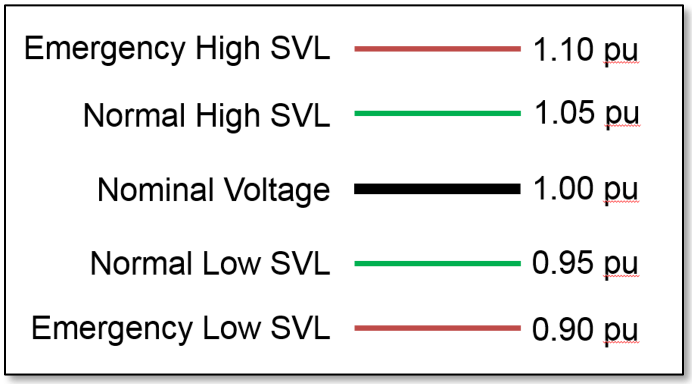

Figure 6. Example of a System Voltage Limit Set

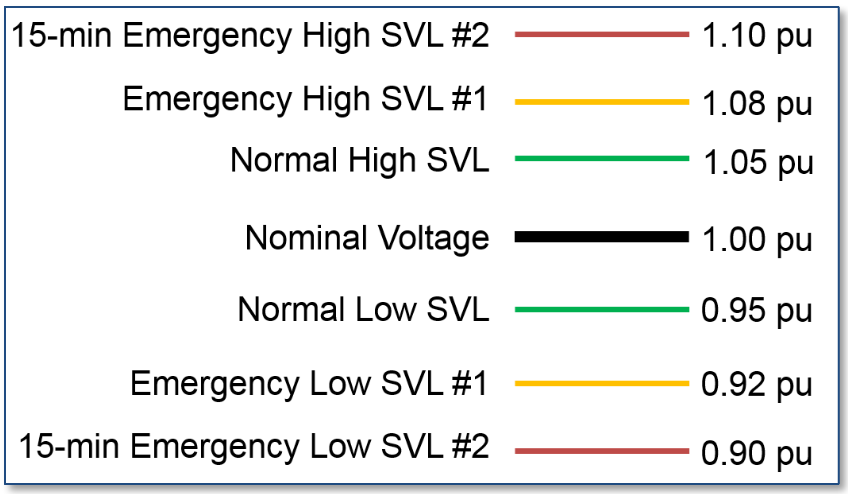

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

Stability Limit Exceedance

Transient and voltage stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area's voltage Stability performance exceeds an SOL that qualifies as an IROL. In this example, the SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

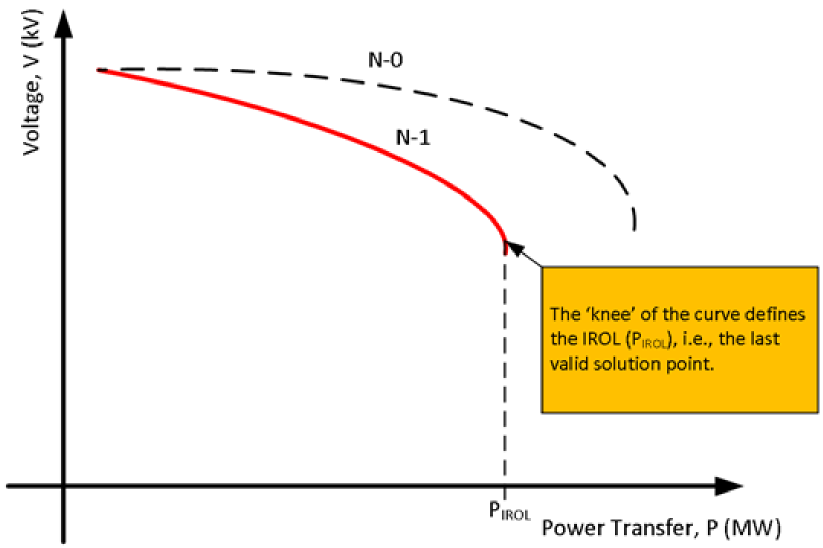

Figure 8. Voltage Stability System Operating Limit Performance Summary

SOL Exceedance and Operating Plans:

SOL exceedances occur when the performance framework described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedances are determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedances are determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedances are identified through the evaluation of the pre-Contingency state and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure acceptable BES performance is maintained, preventing SOL exceedances from escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.	Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.
Emergency (4 hr)	All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.	Use available effective actions and emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.	Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts, generation output levels, Interchange, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Facility Ratings, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Order No. 672 Criteria

EXHBIIT F

<u>Order No. 672 Criteria</u>

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards and modifications to the Glossary of Terms Used in NERC Reliability Standards have met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed Reliability Standards (FAC-011-4, FAC-014-3, FAC-003-5, IRO-008-3, PRC-002-3, PRC-023-5, PRC-026-2, and TOP-001-6) would advance the reliability of the Bulk-Power System ("BPS") by clarifying the framework for establishing and communicating System Operating Limits ("SOLs") used in operations. The use of SOLs is a foundational construct in NERC's Reliability Standards for providing for the reliable operation of the BPS. SOLs are the Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672].

[2] *See id.* at P 321 ("The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.").

See id. at P 324 ("The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.").

configurations, used in operations for monitoring and assessing pre- and post-Contingency operating states. Under the NERC Reliability Standards, SOLs serve as the parameters within which the BES should be operated to provide for reliable pre- and post-contingency System performance.

The proposed standards would also enhance coordination between planning and operations as it relates to analysis input assumptions and System performance criteria.

2. Proposed Reliability Standards must be applicable only to users, owners, and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state which functional entities are subject to the requirements. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in Exhibit G. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology,

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[3] *See id.* at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").

See id. at P 325 ("The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.").

[4] *See id.* at P 326 ("The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.").

thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criteria or measures for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently, but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve their reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards would achieve the reliability goal of improving the manner in which Reliability Coordinators and Transmission Operators establish and communicate SOLs and SOL-related information.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

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[5] *See id.* at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

[6] *See id.* at P 328 ("The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.").

[7] *See id.* at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. The proposed Reliability Standards would enhance reliability by clarifying the roles and responsibilities for establishing and communicating SOLs.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standards would continue to apply consistently throughout North America and do not favor one geographic area or regional model. The proposed Reliability Standards would provide sufficient flexibility to accommodate regional/geographic differences.

Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See id. at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

[8] *See id.* at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.").

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standards would require the same performance by each of the applicable entities.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan is Exhibit B to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. Exhibit H includes a summary of the Reliability Standard development proceedings,

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[9] *See id.* at P 332 ("As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.").

[10] *See id.* at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

[11] *See id.* at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of these proposed Reliability Standards. No comments were received that indicated that one or more of the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[12] *See id.* at P 335 ("Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.").

[13] *See id.* at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G-1

Analysis of Violation Risk Factors and Violation Severity Levels
FAC-011-4

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Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore, a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R6 and Requirement R8 which requires performance framework and description of identifying Interconnection Reliability Operating Limits (IROLs) within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to include a requirement for Part 7.2.	The Reliability Coordinator failed to include a requirement for Part 7.1.	The Reliability Coordinator failed to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.5. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Exhibit G-2

Analysis of Violation Risk Factors and Violation Severity Levels
FAC-014-3

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (“SOL methodology”).

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**Medium**
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	**Medium**

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-1 Requirement R8	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G-3

Analysis of Violation Risk Factors and Violation Severity Levels
IRO-008-3

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in IRO-008. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for IRO-008-3, Requirement R1

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R1

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R2

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R2

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R3

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R3

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R4

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R4

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R5

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R5

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R6

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R6

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	The requirement contains one objective, therefore, a single VRF is assigned.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for IRO-008-3, R7			
Lower	**Moderate**	**High**	**Severe**
			The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

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Exhibit G-4

Analysis of Violation Risk Factors and Violation Severity Levels
TOP-001-6

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TOP-001-6, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R1

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R2

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R3

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R4

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R5

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R6
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R7
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R8
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R9
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R10
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R19
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R19
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R22
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R22
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for TOP-001-6, R25			
Lower	**Moderate**	**High**	**Severe**
			The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit H

Summary of Development and Complete Record of Development

Summary of Development History

The following is a summary of the development record for Project 2015-09 Establish and Communicate System Operating Limits ("Project 2015-09").

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2015-09 SDT members is included in **Exhibit I**.

II. Standard Development History

A. Standard Authorization Request Development and Posting

A Standard Authorization Request ("SAR") was developed by the Periodic Review Team for Project 2015-03 Periodic Review of System Operating Limit Standards. On August 19, 2015, the Standards Committee accepted the SAR for Project 2015-09 and authorized posting the SAR for a 30-day formal comment period from August 20, 2015 through September 21, 2015.[3] Drafting Team nominations were also authorized by the Standards Committee and posted from August 20, 2015 through September 2, 2015.

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2020).

[2] The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

[3] Meeting Minutes, Standards Committee Conference Call, Agenda Item 7 (Project 2015-03 Periodic Review of System Operating Limit Standards and Project 2015-09 System Operating Limits), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20August%2019,%202015.pdf.

B. Informal Comment Draft FAC-011-4, FAC-014-3

The SDT posted proposed revisions to the Reliability Standards FAC-011-3 and FAC-014-2 for an informal comment period from July 14, 2016 through August 12, 2016. FAC-011-4 received 36 sets of responses, including comments from approximately 36 different people from approximately 34 companies representing 8 of the Industry Segments. FAC-014-3 received 33 sets of responses, including comments from approximately 33 different people from approximately 30 companies representing 8 of the Industry Segments.

C. First Posting – Proposed Definitions and Revised SAR

The SDT posted proposed definitions for System Operating Limit ("SOL") and SOL Exceedance to be incorporated into the Glossary of Terms Used in NERC Reliability Standards, and a revised SAR for a 30-day formal comment period from September 29, 2017 through October 30, 2017. The definitions received 36 sets of responses, including comments from approximately 92 different people from approximately 74 companies representing all 10 of the Industry Segments.

D. Second Posting – Draft 1 of Proposed Reliability Standards and SVL Definition, Initial Ballot

The SDT posted draft 1 of proposed Reliability Standards FAC-011-04, FAC-014-3, and FAC-015-1, the proposed retirement of FAC-010-3, the proposed definition of System Voltage Limit ("SVL"), an implementation plan and other supporting materials for a 45-day formal comment period from September 29, 2017 through November 13, 2017 with an initial ballot from November 3, 2017 through November 14, 2017.[4]

This posting received 56 sets of responses, including comments from approximately 166 different people from approximately 106 companies representing all 10 of the Industry Segments. The initial ballot results are summarized in the table below:

	Ballot	Non-binding Poll
Standard	**Quorum / Approval**	**Quorum / Supportive Opinions**
FAC-011-4	87.01% / 58.12%	83.79% / 56.97%
FAC-014-3	86.9% / 63.17%	84.01% / 65.95%
FAC-015-1	86.9% / 56.55%	83.67% / 51.91%
System Voltage Limit	85.85% / 68.59%	
Implementation Plan	85.57% / 76.4%	

E. Third Posting – First and Second Drafts of Proposed Reliability Standards and SOL Definition, Second Ballot

The SDT posted draft 2 of proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1; draft 1 of proposed Reliability Standards CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2; the proposed definition for System Operating Limit; an implementation plan; and other supporting documents for a 45-day formal comment period from

4 The ballots were extended an additional day to reach quorum; the original deadline was November 13, 2017.

August 24, 2018 through October 17, 2018 (it was extended due to typographical errors) with a second ballot for the final 10 days from October 8, 2018 through October 17, 2018.

This posting received 68 sets of responses, including comments from approximately 183 different people from approximately 117 companies representing all 10 of the Industry Segments. The second ballot results are provided in the table below:

	Ballot	Non-binding Poll
Standard	**Quorum / Approval**	**Quorum / Supportive Opinions**
CIP-014-3	83.65% / 67.65%	82% / 65.52%
FAC-003-5	84.35% / 67.46%	82% / 64.77%
FAC-011-4	83.77% / 53.22%	81.38% / 46.2%
FAC-013-3	84.82% / 77.07%	82.59% / 68.52%
FAC-014-3	82.43% / 59.02%	80.27% / 51.96%
FAC-015-1	82.11% / 59.79%	79.93% / 52.22%
PRC-002-3	84.35% / 75.07%	81.73% / 74.44%
PRC-023-5	83.86% / 69.27%	81.52% / 68.39%
PRC-026-2	83.39% / 71.98%	81.19% / 72.67%
Implementation Plan	80.98% / 69.93%	
Proposed Definition - SOL	83.55% / 82.26%	

F. Fourth Posting – First, Second, and Third Drafts of Proposed Reliability Standards, Third Ballot

The SDT posted draft 3 of proposed Reliability Standards FAC-011-4 and FAC-014-3; draft 2 of CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2; draft 1 of IRO-008-3 and TOP-001-6; an implementation plan; and other supporting materials for a 45-day formal comment period from June 19, 2020 through August 26, 2020 (extended to allow greater participation given the age of the project). A third ballot took place from July 24, 2020 through August 26, 2020 (similarly extended). Based on stakeholder comments, the SDT decided to stop development of new Reliability Standard FAC-015-1 and incorporate the reliability issues they proposed to address in that standard into the FAC-011 and FAC-014 Reliability Standards.

This posting recieved 76 sets of responses, including comments from approximately 173 different people from approximately 119 companies representing 10 of the Industry Segments. A table summarizing the third ballot results is below:

	Ballot	**Non-binding Poll**
Standard	**Quorum / Approval**	**Quorum / Supportive Opinions**
CIP-014-3	83.98% / 60.75%	81.48% / 58.50%
FAC-003-5	84.23% / 90.87%	81.73% / 88.32%
FAC-011-4	84.21% / 75.58%	81.35% / 79.26%
FAC-013-3	84.52% / 90.28%	81.15% / 86.98%
FAC-014-3	83.44% / 67.21%	80.57% / 72.82%
PRC-002-3	84.48% / 91.31%	80.98% / 88.78%
PRC-023-5	83.73% / 90.75%	80.43% / 88.50%
PRC-026-2	84.23% / 91.45%	80.67% / 89.16%
TOP-001-6	93.20% / 84.49%	91.18% / 85.21%
IRO-008-3	93.13% / 84.21%	91.48% / 81.17%
Implementation Plan	84.00% / 55.98%	

G. Fifth Posting – Draft 4 of FAC-014-3, Fourth Ballot

The SDT posted draft 4 of FAC-014-3, an updated implementation plan, and other supporting materials for a 45-day formal comment period from October 23, 2020 through December 7, 2020 with a fourth ballot running the final ten days from November 27, 2020 through December 7, 2020. The SDT also decided not to move forward with proposed changes to the FAC-013 and CIP-014 Reliability Standards based on stakeholder comments.

This posting recieved 60 sets of responses, including comments from approximately 139 different people from approximately 107 companies representing 10 of the Industry Segments. The fourth ballot results are summarized in the table below:

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
FAC-014-3	82.82% / 66.61%	79.62% / 71.79%
Implementation Plan	82.41% / 89.79%	

H. Sixth Posting – Draft 5 of FAC-014-3, Fifth Ballot

The SDT posted draft 5 of proposed Reliability Standard FAC-014-3 and its supporting materials for a 45-day formal comment period from February 19, 2021 through April 5, 2021 with a fifth ballot running from March 26, 2021 through April 5, 2021.

The posting received 43 sets of responses, including comments from approximately 122 different people from approximately 93 companies representing all 10 of the Industry Segments. The fifth ballot results are summarized in the table below:

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
FAC-014-3	80.92% / 92.35%	77.64% / 92.97%

I. Final Ballot

Final drafts of proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, IRO-008-3, and TOP-001-6; an implementation plan; and the associated documents were posted for a 10-day final ballot from April 19, 2021 through April 28, 2021. The two proposed definitions (for SOL and SVL) were posted for a separate final ballot from April 29, 2021 through May 10, 2021. The final ballot results are listed in the table below:

Standard	Quorum / Approval
FAC-011-4	85.76% / 82.83%
FAC-014-3	83.44% / 92.34%
FAC-003-5	86.19% / 93.75%
PRC-002-3	86.45% / 94.17%
PRC-023-5	85.67% / 93.55%

Standard	Quorum / Approval
PRC-026-2	86.19% / 94.18%
IRO-008-3	94.42% / 89.59%
TOP-001-6	94.00% / 87.93%
Implementation Plan	84.57% / 93.01%

Definitions	Quorum / Approval
Proposed Definition of System Operating Limit (SOL)	89.67% / 86.43%
Proposed Definition of System Voltage Limit	93.46% / 76.93%

J. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, IRO-008-3, TOP-001-6, the revised definition for SOL, the new definition for SVL, the implementation plan, the retirement of FAC-10-3, and the VRFs and VSLs at its quarterly meeting on May 13, 2021.[5]

[5] NERC, *Board of Trustees Agenda Package*, Agenda Item 5a. (Project 2015-09 Establish and Communicate System Operating Limits) available at https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_May_13_2021_Agenda_Package_PUBLIC_ONLY.pdf.

Complete Record of Development

Project 2015-09 Establish and Communicate System Operating Limits

Related Files

Status

The final ballot concluded at **8 p.m. Eastern, Monday, May 10, 2021** for the following definitions:

- Proposed Definition of System Operating Limit (SOL)
- Proposed Definition of System Voltage Limit

Background

Facilities Design, Connections, and Maintenance (FAC) standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES). This project will revise requirements for determining and communicating these SOLs. Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).

Standards Affected: **CIP-014-2** – Physical Security | **FAC-003-4** – Transmission Vegetation Management | **FAC-010-3** - System Operating Limits Methodology for the Planning Horizon | **FAC-011-3** - System Operating Limits Methodology for the Operations Horizon | **FAC-013-2** – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon | **FAC-014-2** - Establish and Communicate System Operating Limit | **PRC-002-2** – Disturbance Monitoring and Reporting Requirements | **PRC-023-4** – Transmission Relay Loadability | **PRC-026-1** – Relay Performance During Stable Power Swings | **IRO-008-2** - Reliability Coordinator Operational Analyses and Real-time Assessments | **TOP-001-5** – Transmission Operations

Purpose/Industry Need

The project will revise the requirements for determining and communicating SOLs and IROLs to address the issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards. The resulting standard(s) and definition(s) will benefit reliability by improving alignment with approved TPL and proposed TOP and IRO standards. The project may result in development of one or more proposed Reliability Standards and definitions.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **Definitions** **Proposed Definition of System Operating Limit (SOL)** Clean **(283)** | Redline **(284)** Proposed Definition of System Voltage Limit **(285)**	**Final Ballot** Info **(286)** Vote	04/29/21 – 05/10/21	Ballot Results Proposed Definition of SOL **(287)** Proposed Definition of System Voltage Limit **(288)**	
Final Draft **FAC-011-4** Clean **(223)** | Redline to Last Posted **(224)** | Redline to Approved **(225)** **FAC-014-3** Clean **(226)** | Redline to Last Posted **(227)** | Redline to Approved **(228)** **FAC-003-5** Clean **(229)** | Redline to Last Posted **(230)** | Redline to Approved **(231)** **PRC-002-3** Clean **(232)** | Redline to Last Posted **(233)** | Redline to Approved **(234)** **PRC-023-5** Clean **(235)** | Redline to Last Posted **(236)** | Redline to Approved **(237)** **PRC-026-2** Clean **(238)** | Redline to Last Posted **(239)** | Redline to Approved **(240)** **IRO-008-3** Clean **(241)** | Redline to Approved **(242)** **TOP-001-6** Clean **(243)** | Redline to Approved **(244)** **Implementation Plan** Clean **(245)** | Redline **(246)** **Definitions** **Proposed Definition of System Operating Limit (SOL)** Clean **(247)** | Redline **(248)** Proposed Definition of System Voltage Limit **(249)** **Supporting Materials**	**Final Ballot** Info **(273)** Vote	04/19/21 – 04/28/21	Ballot Results FAC-011-4 **(274)** FAC-014-3 **(275)** FAC-003-5 **(276)** PRC-002-3 **(277)** PRC-023-5 **(278)** PRC-026-2 **(279)** IRO-008-3 **(280)** TOP-001-6 **(281)** Implementation Plan **(282)**	

Mapping Documents **FAC-010-3** Clean **(250)** | Redline to Last Posted **(251)** **FAC-011-4** Clean **(252)** | Redline to Last Posted **(253)** **FAC-014-3** Clean **(254)** | Redline to Last Posted **(255)** IRO-008-3 **(256)** **TOP-001-6** Clean **(257)** | Redline to Last Posted **(258)** **VRF/VSL Justification** **FAC-011-4** Clean **(259)** | Redline to Last Posted **(260)** **FAC-014-3** Clean **(261)** | Redline to Last Posted **(262)** **IRO-008-3** Clean **(263)** | Redline to Last Posted **(264)** **TOP-001-6** Clean **(265)** | Redline to Last Posted **(266)** **Requirement Rationales** FAC-011-4 **(267)** FAC-014-3 **(268)** IRO-008-3 **(269)** TOP-001-6 **(270)** **NERC SOL Whitepaper** Clean **(271)** | Redline to Last Posted **(272)**				
Draft 5 **FAC-014-3** Clean **(208)** | Redline to Last Posted **(209)** **Supporting Materials** Unofficial Comment Form (Word) **(210)** **Mapping Document** **FAC-014-3** Clean **(211)** | Redline to Last Posted **(212)** **VRF/VSL Justification** **FAC-014-3** Clean **(213)** | Redline to Last Posted **(214)** **Requirement Rationale** FAC-014-3 **(215)** CIP-002 and CIP-014 **(216)**	Additional Ballots and Non-binding Polls Info **(220)** Vote	02/19/21 - 04/05/21	Ballot Results FAC-014-3 **(221)** Non-binding Poll Results FAC-014-3 **(222)**	
	Comment Period Info **(217)** Submit Comments	02/19/21 - 04/05/21	Comments Received **(218)**	Consideration of Comments **(219)**
Draft 4 **FAC-014-3** Clean **(191)** | Redline to Last Posted **(192)** **Implementation Plan** Clean **(193)** | Redline to Last Posted **(194)** **Supporting Materials** Unofficial Comment Form (Word) **(195)**	Additional Ballots and Non-binding Polls Info **(204)** Vote	11/27/20 - 12/07/20	Ballot Results FAC-014-3 **(205)** Implementation Plan **(206)** Non-binding Poll Results	

Mapping Document (Updated) **FAC-014-3** Clean **(196)** | Redline to Last Posted **(197)** **VRF/VSL Justification** **FAC-014-3** Clean **(198)** | Redline to Last Posted **(199)** **Requirement Rationale** FAC-014-3 **(200)**	Comment Period Info **(201)** Submit Comments	10/23/20 - 12/07/20	FAC-014-3 **(207)** Comments Received **(202)**	Consideration of Comments **(203)**
Draft 3 **FAC-011-4** Clean **(133)** | Redline to Last Posted **(134)** **FAC-014-3** Clean **(135)** | Redline to Last Posted **(136)** **Implementation Plan** Clean **(137)** | Redline to Last Posted **(138)** **Draft 2** **CIP-014-3** Clean **(139)** | Redline to Last Posted **(140)** **FAC-003-5** Clean **(141)** | Redline to Last Posted **(142)** **FAC-013-3** Clean **(143)** | Redline to Last Posted **(144)** **PRC-002-3** Clean **(145)** | Redline to Last Posted **(146)** **PRC-023-5** Clean **(147)** | Redline to Last Posted **(148)** **PRC-026-2** Clean **(149)** | Redline to Last Posted **(150)** **Draft 1** **IRO-008-3** Clean **(151)** | Redline to Approved **(152)** **TOP-001-6** Clean **(153)** | Redline to Approved **(154)** **Supporting Materials** Unofficial Comment Form (Word) **(155)** **Mapping Documents** **FAC-010-3** Clean **(156)** | Redline to Last Posted **(157)** **FAC-011-4** Clean **(158)** | Redline to Last Posted **(159)** **FAC-014-3** Clean **(160)** | Redline to Last Posted **(161)** IRO-008-3 **(162)** TOP-001-6 **(163)**	Initial / Additional Ballots and Non-binding Polls Extended Info **(186)** Updated Info **(187)** Info **(188)** Vote	07/24/20 - 08/26/20 (Extended)	Ballot Results **(189)** Non-Binding Poll Results **(190)**	
	Comment Period Extended Info **(180)** Updated Info **(181)** Info **(182)** Submit Comments	06/19/20 - 08/26/20 (Extended)	Comments Received **(183)**	Consideration of Comments **(184)** (Complete set of questions) Consideration of Comments **(185)** (Questions 4 and 5 regarding FAC-014)
	Join Ballot Pools	06/19/20 - 07/20/20		

VRF/VSL Justifications **FAC-011-4** Clean **(164)** | Redline to Last Posted **(165)** **FAC-014-3** Clean **(166)** | Redline to Last Posted **(167)** IRO-008-3 **(168)** TOP-001-6 **(169)** **Requirement Rationales** FAC-011-4 **(170)** FAC-014-3 **(171)** IRO-008-3 **(172)** TOP-001-6 **(173)** **NERC SOL Whitepaper** Clean **(174)** | Redline to Last Posted **(175)** **Draft Reliability Standard Audit Worksheets (RSAWs)** FAC-011-4 **(176)** FAC-014-3 **(177)** IRO-008-3 **(178)** TOP-001-6 **(179)**	Send RSAW feedback to: RSAWfeedback@nerc.net			
Draft 2 **FAC-011-4** Clean **(62)** | Redline to Last Posted **(63)** **FAC-014-3** Clean **(64)** | Redline to Last Posted **(65)** **FAC-015-1 (Updated)** Clean **(66)** | Redline to Last Posted **(67)** **Implementation Plan** Clean **(68)** | Redline to Last Posted **(69)** **Draft 1** **CIP-014-3** Clean **(70)**| Redline to Last Approved **(71)** **FAC-003-5** Clean **(72)**| Redline to Last Approved **(73)** **FAC-013-3** Clean **(74)** | Redline to Last Approved **(75)** **PRC-002-3** Clean **(76)** | Redline to Last Approved **(77)** **PRC-023-5** Clean **(78)** | Redline to Last Approved **(79)** **PRC-026-2** Clean **(80)** | Redline to Last Approved **(81)** **Proposed Definition of System Operating Limit (82)** **Supporting Materials** Unofficial Comment Form (Word) **(83)**	Initial / Additional Ballots and Non-binding Polls Info **(112)** Vote	10/08/18 - 10/17/18	Ballot Results FAC-011-4 **(113)** FAC-014-3 **(114)** FAC-015-1 **(115)** CIP-014-3 **(116)** FAC-003-5 **(117)** FAC-013-3 **(118)** PRC-002-3 **(119)** PRC-023-5 **(120)** PRC-026-2 **(121)** Implementation Plan **(122)** System Operating Limit Definition **(123)** Non-binding Poll Results FAC-011-4 **(124)** FAC-014-3 **(125)** FAC-015-1 **(126)** CIP-014-3 **(127)** FAC-003-5 **(128)** FAC-013-3 **(129)** PRC-002-3 **(130)** PRC-023-5 **(131)** PRC-026-2 **(132)**	

Mapping Documents FAC-010-3 Clean **(84)** | Redline to Last Posted **(85)** FAC-011-3 Clean **(86)** | Redline to Last Posted **(87)** FAC-014-2 Clean **(88)** | Redline to Last Posted **(89)** Standards Impacted by Retirement of FAC-010-3 (Word) **(90)** **VRF/VSL Justifications** FAC-011-4 Clean **(91)** | Redline to Last Posted **(92)** FAC-014-3 Clean **(93)** | Redline to Last Posted **(94)** FAC-015-1 Clean **(95)** | Redline to Last Posted **(96)** **Requirement Rationales** FAC-010-3 / FAC-015-1 SDT Rationale Clean **(97)** | Redline to Last Posted **(98)** FAC-011-4 Clean **(99)** | Redline to Last Posted **(100)** FAC-014-3 Clean **(101)** | Redline to Last Posted **(102)** FAC-015-1 **(Updated)** Clean **(103)**| Redline to Last Posted **(104)**	Comment Period Info **(109)** Submit Comments	08/24/18 - 10/17/18* (extended due to typographical errors)	Comments Received **(110)**	Consideration of Comments **(111)**
	Join Ballot Pools	08/24/18 - 09/24/18		
	Info**(108)** Send RSAW feedback to: RSAWfeedback@nerc.net	Coming Soon		
SOL Definition Impact **(105)** NERC SOL Whitepaper Clean **(106)** | Redline to Last Posted **(107)** -- **Draft 1** Retirement of FAC-010-3 **(24)** **FAC-011-4** Clean **(25)** | Redline to Last Approved **(26)** **FAC-014-3** Clean **(27)** | Redline to Last Approved **(28)** **FAC-015-1 (29)** Proposed Definition of System Voltage Limit **(30)** Implementation Plan **(31)** **Supporting Materials** Unofficial Comment Form (Word) **(32)** **Mapping Documents** FAC-010-3 **(33)** FAC-011-3 **(34)** FAC-014-2 **(35)** **VRF/VSL Justifications** FAC-011-4 **(36)** FAC-014-3 **(37)** FAC-015-1 **(38)**	Initial Ballots and Non-binding Polls Updated Info **(52)** Info **(53)** Vote	11/03/17 – 11/13/17 The ballots were extended an additional day to reach quorum and closed November 14, 2017	Ballot Results FAC-011-4 **(54)** FAC-014-3 **(55)** FAC-015-1 **(56)** Implementation Plan **(57)** System Voltage Limit Definition **(58)** Non-binding Poll Results FAC-011-4 **(59)** FAC-014-3 **(60)** FAC-015-1 **(61)**	

Requirement Rationales FAC-010-3 / FAC-015-1 **(39)** SDT Rationale **(40)** FAC-011-4 **(41)** FAC-014-3 **(42)** FAC-015-1 **(43)** Standards Impacted by Retirement of FAC-010-3 **(44)**	Comment Period Info **(49)** Submit Comments	09/29/17 – 11/13/17	Comments Received **(50)**	Consideration of Comments **(51)**
	Join Ballot Pools	09/29/17 – 10/30/17		
Draft Reliability Standard Audit Worksheets (RSAWs) FAC-011-4 **(45)** FAC-014-3 **(46)** FAC-015-1 **(47)**	Info **(48)** Send RSAW feedback to: RSAWfeedback@nerc.net	10/17/17 - 11/13/17		
Definitions Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance **(15)** **Supporting Materials** Standard Authorization Request Clean **(16)** | Redline to Last Posted **(17)** Unofficial Comment Form (Word) **(18)** SOL / SOL Exceedance Rationale **(19)** SOL/SOL Exceedance Standards Impacted **(20)**	Comment Period Info **(21)** Submit Comments	09/29/17 – 10/30/17	Comments Received **(22)**	Consideration of Comments **(23)**
Informal Comment Draft FAC-011-4 **(7)** FAC-014-3 **(8)** **Supporting Documents** FAC-011-4 Unofficial Comment Form (Word) **(9)** FAC-014-3 Unofficial Comment Form (Word) **(10)** Summary of Proposed Revisions **(11)**	Comment Period Info **(12)** Submit Comments	07/14/16 - 08/12/16	Comments Received FAC-011-4 **(13)** FAC-014-3 **(14)**	
Standard Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	08/20/15 - 09/21/15	Comments Received **(6)**	
Drafting Team Nominations Supporting Materials Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	08/20/15 - 09/02/15		

Unofficial Nomination Form

Project 2015-09 – Establish and Communicate System Operating Limits

Please submit a completed electronic nomination form as soon as possible, but no later than **September 2, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, please contact Lacey Ourso.

By submitting a nomination form, you are indicating that if appointed by the Standards Committee, you are willing to attend and actively participate in the drafting team face-to-face meetings and conference calls. Failure to do so may result in your removal from the drafting team.

The time commitment for this project is expected to be an average of two face-to-face meetings per quarter (generally two full working days each meeting), with conference calls scheduled as needed. Also, drafting team members will have side projects, either individually or by sub-group, to present to the larger team for discussion and review. Lastly, an important component of the drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot. Previous drafting or review team experience is beneficial but not required.

Project 2015-09 Establish and Communicate System Operating Limits
The purpose of this project is to revise requirements for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES). Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs). The project will revise the necessary requirements and definitions in order to address the issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards.

Standards affected: FAC-010, FAC-011, and FAC-014

NERC is seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise with System Operating Limits methodologies, Facility Ratings, and Interconnection Reliability Operating Limits and communicating the methodologies across the United States and/or Canada.

Experience with developing standards inside or outside (*e.g.*, IEEE, NAESB, ANSI) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Please provide the following information for the nominee:	
Name:	
Title:	
Organization:	
Address:	
Telephone:	
Email:	

Please briefly describe the nominee's experience and qualifications to serve on the project team:

If you are currently a member of any NERC SAR or standard drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC SAR or standard drafting team, please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following SAR or standard drafting team(s):

Select each NERC Region in which you have experience relevant to Project 2015-09:

☐ TRE	☐ NPCC	☐ SPP
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:

☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the name and contact information for two references that may attest to your technical qualifications and ability to work well in a group:			
Name:		Name:	
Organization:		Organization:	
Telephone:		Telephone:	
Email:		Email:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Standard Drafting Team Nomination Period Open through September 2, 2015

Now Available

Nominations are being sought for standard drafting team (SDT or team) members through **8 p.m. Eastern, Wednesday, September 2, 2015.**

Use the electronic form to submit a nomination. If you experience any difficulty using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to participate in the SDT face-to-face meetings and conference calls.

The time commitment for this project is expected to be an average of two face-to-face meetings per quarter (typically two full working days each meeting), with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Team members will have side projects, either individually or by sub-group, to present to the entire team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous SDT experience is beneficial but not required.

Project 2015-09 Establish and Communicate System Operating Limits

The purpose of this project is to revise requirements for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES). Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs). The project will revise the necessary requirements and definitions in order to address the issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards.

Next Steps
The Standards Committee is expected to appoint members to the SDT in September 2015. Nominees will be notified shortly after they have been appointed to the team**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Lacey Ourso (via email) or at (404) 446-2581.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Establish and Communicate System Operating Limits		
Date Submitted:	July 29, 2015		
SAR Requester Information			
Name:	Jason Smith		
Organization:	Southwest Power Pool		
Telephone:	501.614.3293	E-mail:	jsmith@spp.org
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The project will revise requirements for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES).
Industry Need (What is the industry problem this request is trying to solve?):
FAC standards fulfill an important reliability objective for determining and communicating SOLs used in the reliable planning and operation of the Bulk Electric System (BES). Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed standards project will revise the requirements for determining and communicating SOLs and IROLs to address issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards. The resulting standard(s) and definition(s) will benefit reliability by improving alignment with approved TPL and proposed TOP and IRO standards. The project may result in development of one or more proposed Reliability Standards and definitions and may consolidate reliability objectives from the existing three Reliability Standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The standards development project will consider recommendations from Project 2015-03 Periodic Review of System Operating Limits. This review included inputs from the Independent Experts Review Project (IERP), FERC Directives, and Paragraph 81 concepts. When completed, the project will address all issues identified in the Periodic Review Recommendations (PRRs) for FAC-010-3, FAC-011-3, and FAC-014-2, including: • Propose retirement of FAC-010-3. BES planning is covered under approved TPL-001-4 which provides comprehensive requirements for a variety of contingencies. The standards project will propose retirement of FAC-010-3. • Clarify acceptable System performance criteria for the operations time horizon. The proposed standards project will develop continent-wide standards for system performance in the operations time horizon to replace currently-enforceable requirements in FAC-011-3 that specify acceptable system performance through the Reliability Coordinator's (RC) SOL methodology. Development of a table similar to TPL-001-4 Table 1 with appropriate requirements for the operations time horizon would enhance clarity and consistency. This project will determine the appropriate family of standards for this table. • Propose requirements to address identified reliability issues. Requirement(s) will be developed to address FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (P6 and P41). FERC Order No. 777 states: *“As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners.”* (P 6) *“NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners.*

SAR Information
However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41) • Revise or develop new definitions to provide clarity and alignment with how SOLs are treated in proposed TOP and IRO standards developed in Project 2014-03 Revisions to TOP and IRO Standards. This work may include, but is not limited to, revising the definition of System Operating Limit (SOL) and creating a new definition for SOL Exceedance. The project will also address the issues identified in the FAC PRRs related to the application of the IROL term. Proposed definitions should provide clarity and consistency to establishing SOLs and IROLs and promote a common understanding of what it means to establish and exceed SOLs. • Clarify responsibilities for establishing and communicating SOLs. The project will propose requirements to clearly delineate the functional entity responsibilities for determining and communicating each type of SOL (Facility Ratings, System voltage limits, voltage stability limits, and transient stability limits) where not already addressed in existing standards (*e.g.*, FAC-008). • Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating System Operating Limits. • Revise requirements to conform to the Results-Based Standards format, functional entity terms found in the NERC Functional Model, guidelines for compliance elements, and NERC standards for content and quality (Independent Experts Review Project).

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards	
Standard No.	Explanation
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to plan and operate within SOLs and IROLs. The proposed standards and definitions are pending regulatory approval.

Related Standards	
FAC-010-3	Project 2015-03 PRR recommends retirement.
FAC-011-3	Project 2015-03 PRR recommends revision.
FAC-014-2	Project 2015-03 PRR recommends revision.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	Regional Differences (Section E) is being reviewed through the WECC standards process.

Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits Standards Authorization Request (SAR) 30-day informal comment period

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft SAR. The electronic comment form must be completed by 8:00 p.m. EST on **Monday, September 21, 2015.**

If you have questions please contact Lacey Ourso by email or by telephone at 404-446-2581.

The 2015-09 Establish and Communicate System Operating Limits project page may be accessed by clicking here.

Background Information

Facilities Design, Connections, and Maintenance (FAC) standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES). Project 2015-09 will revise requirements for determining and communicating these SOLs and address the issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards. Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).

Instructions for Commenting

Please enter comments in simple text format. Bullets, numbers, and special formatting will **not** be retained.

Questions

1. Do you agree with the proposed scope for Project 2015-09 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. If you have additional comments on this SAR that you have not provided in your above responses, please provide them here:

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits
Standard Authorization Request

Informal Comment Period Open through September 21, 2015

Now Available

A 30-day informal comment period for the **Project 2015-09 Establish and Communicate System Operating Limits** Standard Authorization Request (SAR) is open through **8 p.m. Eastern, Monday, September 21, 2015**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Lacey Ourso (via email) or at (404) 446-2581.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2015-09 Establish and Communicate System Operating Limits SAR

Description

Start Date 8/20/2015

End Date 9/21/2015

Associated Ballots

Survey Questions

1. Do you agree with the proposed scope for Project 2015-09 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Yes

No

2. If you have additional comments on this SAR that you have not provided in your above responses, please provide them here:

Responses By Question

1. Do you agree with the proposed scope for Project 2015-09 as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

We generally concur with the proposed scope, but have a couple of specific comments on FAC-011 and FAC-014. Please see our comments under Q2, below.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer: Yes

Answer Comment:

The SAR descriptive sections do not indicate why the GO and GOP entities are checked in the applicability section. The SOL and IROL topics generally do not involve those entities. The SAR authors should provide a clear rationale for including the GO and GOP functions.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC believes that the retirement of FAC-010 R1 and R4 would create partial reliability gaps for the four types of SOLs – Facility Ratings, Voltage Limits, Transient Stability Limits and Voltage Stability Limits. Therefore, ATC proposes the following revisions to the SAR:

· ATC recommends to replace "Propose retirement of FAC-010-3" item with "Propose to move the requirements of FAC-014-2 to FAC-010-4 and FAC-011-4 ; and retire FAC-014-2" in the SAR Detailed Description.

· To clarify applicability of the FAC- Standard's requirements, ATC recommends to move all of the planning horizon SOL requirements from FAC-014 -2 to a new FAC-010-4 standard and all of the operating horizon requirements from FAC-014-2 to a new FAC-011-4 standard, and retire the FAC-014-2 standard rather than retire FAC-010-3. Operating horizon SOLs and planning horizon SOLs should be separated because they involve different functional entities and have different reliability risks. The SAR does not propose to discontinue the mixing of operating horizon and planning horizon requirements in the same FAC-014-2 standard or to discontinue mixing planning and operating horizon requirements within the same Requirement R5.

Document Name:

Likes: 0

Dislikes: 0

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

As described previously in Texas RE's comments on the periodic review (2015-03), Texas RE does not agree with the retirement of FAC-010-3 because TPL-001-4 as it currently stands is an incomplete and insufficient replacement for the planning horizon (both near and long-term). Indeed, TPL-001-4 says nothing specific about operating limits other than to characterize them as vague concepts such as "applicable" or "acceptable." Requirements for entities to develop documented methodologies for planning horizon operating limits are essential for the following reasons.

If FAC-010 is eliminated, there would be no requirement to create a methodology to be used in TPL-001-4. Without a methodology indicating expectations, an entity might not know if it had and SOL or IROL or if it exceeded and SOL or IROL. Without a methodology that supports what an SOL or IROL is, planners would not be able to coordinate efforts and could lead to inconsistent planning. If entities do not have consistent limits and know how the limits are derived, it would not be able to adequately plan well enough for operations and for the future. Limits might be arbitrarily decided upon and inconsistent. From a reliability and compliance perspective, issues are less likely to occur if entities have a plan. Additionally, without a requirement to have a SOL Methodology, entities may not be prepared for an event and thus run the risk of losing all the load in an area instead of some of the load in the area. Texas RE agrees that some SOLs are determined in the real-time or near real-time, but some SOLs are also determined in the planning horizon. If FAC-010 were eliminated, entities might not determine SOLs in the planning horizon.

Rather than retiring FAC-010, Texas RE recommends the drafting team consider combining FAC-010 and FAC-011 into a single standard. The process or methodology to determine SOLs should be the same for both the operations and planning horizon. Obviously, the actual limit for a specific element used in an assessment may be different between the operations and planning horizons, but the methodology on how the limit is determined should be consistent between planning and operations. This approach has worked in our region, as ERCOT, acting as both the RC and PC, issued a combined FAC methodology document that covers both the operations and planning horizons.

Texas RE does not agree with the reasoning for a SAR. The SAR is claims to promote consistency and lessen confusion but it is unclear why "consistency" in "acceptable system performance requirements" discussed in FAC-011 R2 between Interconnections or even Regions would improve reliability. A uniform list of performance requirements is useful in numerous ways, however, it would be very difficult to capture every risk to reliability in each RC area. Uniformity in BES implementation does not exist between and often within different regions.

Texas RE also does not agree that the existing requirements and the SOL definition contribute to confusion and a lack of continent-wide consistency as previously stated by the Periodic Review Team (PRT). Texas RE is not aware of instances where the existing requirements have contributed to confusion or a lack of consistency.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Selected Answer: No

Answer Comment:

We propose a wording change to the “Purpose” statement. Delete the words “planning and” from the statement because the focus of this SAR should be to cover the determination and communications of System Operating Limits (SOLs) in the real-time operations time horizon.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

BPA agrees with the scope of the SAR to retire FAC-010.

BPA has no comments on FAC-011.

BPA suggests that the scope of FAC-014 needs to be clarified. Is the main goal foı communication of IROL information?

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2015-09 Establish and Communicate SOLs - FAC-010-3, FAC-011-3, FAC-014-2

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

Suggest a revision to the “Purpose” statement. Delete the words “planning and” from the statement because the focus of this SAR should be to cover the determination and communications of System Operating Limits (SOLs) in the Real-time operations time horizon.

Document Name:

Likes: 0

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Oncor Electric Delivery - 1 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Allan George	Sunflower Electric Power Corporation	SPP	1
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jonathan Hayes	Southwest Power Pool	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5

James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Brandon Levander	Nebraska Public Power District	MRO	1,3,5
Kevin Giles	Westar Energy	SPP	1,3,5,6
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

We feel like the SAR is a good broad scope and does not seem to over reach in intent.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We agree with the scope of this project, to “revise requirements for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES).”

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. If you have additional comments on this SAR that you have not provided in your above responses, please provide them here:

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion NCP

Group Member Name	Entity	Region	Segments
Mike Garton	NERC Compliance Policy	NPCC	5,6
Randi Heise	NERC Compliance Policy	SERC	1,3,5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

We would like to reiterate our comments submitted when the PRT posted its initial recommendations in May, 2105 for comment:

a. We do not agree with the proposal to include in R3.3 a list of planning events in TPL-001-4 to be considered in operations. Since the planning studies are performed under a confined set of system conditions, there is no assurance that the power system could be operated to respect a particular planning event under all possible conditions to be encountered in operations.

Furthermore, if a list of multiple events is included in R3.3, then FAC-014-2 R6 would not be required anymore, and the proposal to revise FAC-014-2 indicated suggested changes to R6, but not deletion of R6, thus this proposal is not consistent with the proposed scope of update to R6 in FAC-014-2.

b. We agree with this recommendation to revise the definitions of SOL and IROL. When developing the revised definition to IROL, we suggest the SDT to consider introducing the concept of "impacts on interconnected systems" to distinguish between instability of local nature (SOLs) and instability having a wider area impact (IROLs).

That said, we do not agree with the proposed SOL Exceedance definition. For example, we do not agree with the second bullet which says: "highest available Facility Rating", which in our view should be the "applicable rating", which may not be the highest (e.g. 5-minute rating > 15-minute rating, but the applicable rating could be the latter due to available control actions that can be implemented with the 5 and minute time frames). We also disagree with the fifth bullet. An SOL determined based on transient or voltage stability concerns are either a MW flow level on a line or defined interface, or the applicable pre or post-contingency bus voltages. The proposed definition (the bullet) ties the SOL exceedance to stability or voltage performance (not a value or level), which should have been observed in the SOL/IROL calculation state. We suggest the SDT to consider rewording it accordingly.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Randall Hubbard - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - FRCC,WECC,TRE,SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc..	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R. Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter

Randall Hubbard

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

FRCC,WECC,TRE,SERC

Selected Answer:

Answer Comment:

See number 1.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

The proposed SAR states that this project "may result in development of one or more proposed Reliability Standards and definitions", yet the SAR Type field only has "Revision to existing Standard" and "Withdrawal of existing Standard" selected. "New Standard" remains un-checked.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

The development of performance requirements for the operations horizon similar to those found in Table 1 of TPL-001-4 could create a burden on the Reliability Coordinator to classify events in real-time to ensure the System meets the performance requirements. This would create an extra layer of complexity for operators, and could hinder their ability to focus on real-time operations.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Selected Answer:

Answer Comment:

On page 3, we suggest revising the sentence “Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating System Operating Limit.” Please substitute the word “planning” with “owning entities.” Also, please add a clarification, “(i.e., from the TOs, DPs, and GOs to the TOPs).”

The revised sentence should read as follows: “Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the owning entities and the operating entities (i.e., from TOs, DPs and GOs to the TOPs) for establishing and communicating System Operating Limits.

Operating entities should not go to the planning entity for the basic system descriptive information, such as feeder and equipment ratings. Operating entities should go back to the original responsible source of this information, i.e., the asset owning entity (TO or GO).

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

N/A

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2015-09 Establish and Communicate SOLs - FAC-010-3, FAC-011-3, FAC-014-2

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

The SAR proposes to retire FAC-010-3 because BES planning is addressed in TPL-001-4. While both standards cover planning, TPL-001-4 does not specifically address SOLs.

Because the severity of facility ratings are time dependent, a definition for operations time horizon needs to be developed. Suggest Operations Time Horizon be defined as the time period it takes to ensure stable system operation following a Real-time Assessment. Specifics can be incorporated in the standard.

On page 3, suggest revising the sentence "Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating System Operating Limit." Please substitute the word "planning" with "owning entities." Also, please add a clarification, "(i.e., from the TOs, DPs, and GOs to the TOPs)." The revised sentence would then read as follows: "Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the owning entities and the operating entities (i.e., from TOs, DPs and GOs to the TOPs) for establishing and communicating System Operating Limits.

Operating entities should not go to the planning entity for the basic system descriptive information, such as feeder and equipment ratings. Operating entities should go back to the original responsible source of this information, i.e., the asset owning entity (TO or GO).

Document Name:

Likes: 0

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

The SAR descriptive sections do not indicate why the GO and GOP entities are checked in the applicability section. The SOL and IROL topics generally do not involve those entities. With no additional description of the scope of the revisions to be considered, we suggest the GO and GOP should be removed from the SAR applicability.

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Oncor Electric Delivery - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Allan George	Sunflower Electric Power Corporation	SPP	1
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jonathan Hayes	Southwest Power Pool	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5
Ron Gunderson	Nebraska Public Power District	MRO	1,3,5
Brandon Levander	Nebraska Public Power District	MRO	1,3,5
Kevin Giles	Westar Energy	SPP	1,3,5,6
Sing Tay	Oklahom Gas and Electric	SPP	1,3,5,6

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We support a more standardized SOL determination and establishment methodology. A single, continent-wide methodology, or improved definition that results in more consistent SOL philosophy would be welcome.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

We believe the wording within the Detailed Description Section of this SAR should be stronger. The SDT should address, not just "consider," the recommendations of the Project 2015□03 Periodic Review of System Operating Limits SDT, the Independent Experts Review Project (IERP), FERC Directives, and Paragraph 81 concepts. The SDT has an opportunity to address several Paragraph 81 requirements and even the retirement of FAC□010□3, and we feel a consideration of these recommendations doesn't adequately provide direction to the SDT that industry expects. We recommend changing the word "consider" to "address" to ensure that the drafting team will thoroughly review each item.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

New or Modified Term(s) Used in NERC Reliability Standards

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs (“SOL Methodology”) within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above UVLS relay settings;

3.4. Identify the lowest allowable System voltage limit;

3.5. Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault:

- generator;
- Transmission circuit;
- transformer;
- shunt device;
- single pole of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

 4.1. Functional Entities:

 4.1.1. Reliability Coordinator

 4.1.2. Transmission Operator

 4.1.3. Planning Coordinator

 4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_v;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

Unofficial Comment Form for FAC-011-4

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits**. The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

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[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits." Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition	operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability) • system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	of “SOL Exceedance” will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term “stability limitation” rather than “transient stability limit,” “voltage stability limit” or the Glossary term “Stability Limit.” The intent of the SDT is that “stability limitation” is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term “Stability Limits” is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO	

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating; • Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition.	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an "SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. <u>For bullet item 3</u>: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." <u>For bullet items 4 and 5</u>: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to	types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • <u>TOP-002-4 Requirement R1</u> - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs). • <u>TOP-002-4 Requirement R2</u> - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL)

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Question 1: Given how the revisions are intended to work together with the revised TOP and IRO Reliability Standards (including the definitions of OPA, RTA and Operating Plan), do you agree with the proposed revisions to the definition of SOL and new definition of “SOL Exceedance”? If not, please explain why you do not support the revisions, and what revisions you propose to align the definition(s) with the revised TOP and IRO Reliability Standards.

☐ Yes
☐ No
Comments:

Question 2: The suggested revisions would mean that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. OPAs and RTAs are performed to determine whether these SOLs may potentially be exceeded (through an OPA) or are actually being exceeded (through a RTA). Operating Plans are developed to address “’SOL Exceedances.” Do you believe the proposed revisions to the definition of SOL (and companion definition of “SOL Exceedance”) allow for a clear distinction between “what the limits are” and “how the system should be operated”?

☐ Yes
☐ No
Comments:

Question 3: Do you agree with removing "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post- Contingency" concepts from the definition of SOL? If no, please explain your concerns.

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Question: None. All related questions have been incorporated below (*see*, questions regarding proposed Requirements R2, R6 and Part 3.1).

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined	**<u>Background regarding existing standards *not* under revision by SDT:</u>** • <u>FAC-008-3 Requirements R1, R2 and R3</u>– GOs and TOs are required to have a methodology for developing Facility Ratings. • <u>FAC-008-3 Requirement R6</u>– GOs and TOs shall establish Facility Ratings consistent with its methodology. • <u>FAC-008-3 Requirements R7 and R8</u>– must provide their Facility Ratings to the RC, TOP and other functional entities. **<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R1</u>- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • <u>FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)</u>- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	prescribed conditions/states, remain within their Facility Ratings.

<u>Question 4</u>: Do you agree that the TOP should determine the appropriate Facility Ratings for use in operations, in accordance with the requirements set in the RC SOL Methodology? Note: This assumes the Facility owner will continue to provide the Facility Ratings to the RC and TOP as currently required under FAC-008. The RC Methodology will simply describe the manner in which the TOP determines which of those owner-provided Facility Ratings are appropriate for use in operations.

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable	**<u>Background regarding existing standards *not* under revision by SDT:</u>**

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and, **3.6.** Address coordination of System voltage limits between adjacent	operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	• FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-Contingencies) and remain within their thermal and voltage limits. [Proposed

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Transmission Operators in its Reliability Coordinator Area.		definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Question 5: Do you agree that the TOP should establish the System voltage limits pursuant to the RC SOL Methodology, and that the proposed Requirement R3 provides sufficient clarity for what the RC SOL Methodology must include?

☐ Yes
☐ No
Comments:

Question 6: Is it clear what System voltage limits are? Does a definition for "System Voltage Limits" need to be created? A draft definition under consideration by the SDT is "System Voltage Limits: The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations." Please provide your perspective on whether, currently, it is clear what is meant by System voltage limits, and if not, what you believe to be the appropriate definition.

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions	**<u>Background regarding existing standards *not* under revision by SDT:</u>** • <u>IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3)</u> – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • <u>IRO-008-2, Requirement R1</u> – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • <u>MOD-001-2, Requirement R1 (Part 1.1)</u> – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator; • Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;	continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: <u>Part 4.1</u> - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. <u>Part 4.2</u> - Meet the performance criteria for certain identified Contingencies (listed in the standard). <u>Part 4.3</u> - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-014-2, Requirement R6 (Parts 6.1 and 6.2)</u> – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • <u>FAC-011-3 Requirement R2 (Part 2.1)</u> - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • <u>FAC-011-3 Requirement R2 (Part 2.2)</u> - *[Maps to proposed Part 4.2]* • <u>FAC-011-3 Requirement R2 (Part 3.6)</u> - *[Maps to proposed Part 4.3]* • <u>FAC-011-3 Requirement R3 (Parts 3.1 and 3.5)</u> – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.	believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. <u>Part 4.4</u> – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the stability limitations provided by the Planning Coordinator. <u>Part 4.5</u> – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. <u>Part 4.6</u> – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the	

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	proposed FAC-014-3 Requirement R3 for further explanation).	

Question 7: Do you agree that the proposed use of the word stability "limitations" is a better choice than "limit" to capture the full breadth of all phenomena and determination methods/time frames for stability concerns?

☐ Yes
☐ No
Comments:

Question 8: With regard to proposed Part 4.1: Do you agree that the RC SOL Methodology should have criteria that consider *all* items in Parts 4.1.1 – 4.1.4? Are there additional criteria that should be included? If yes, please list and explain. Are there criteria that are included, that you believe should *not* be included?

☐ Yes
☐ No
Comments:

Question 9: With regard to proposed Part 4.2: Do you agree that the RC SOL Methodology should consider the contingencies listed in Parts 4.2.1 and 4.2.2? Are there additional Contingencies that should be included? If yes, please list and explain. Are there Contingencies that are included, but you believe should *not* be included?

☐ Yes
☐ No
Comments:

<u>Question 10</u>: With regard to proposed Part 4.3: When instability risks are identified, there are various studies or assessments that analyze different transfer levels, load levels and generation dispatch combinations. The intent of Part 4.3 is to ensure that the RC SOL Methodology adequately describes how these various factors are considered in the identification of instability risks. In the identification of stability risks, the RC SOL Methodology should consider the levels of transfers, load and generation dispatch. Should the RC SOL Methodology include a description of any additional types of information?

a. Should proposed Part 4.3 specifically include "offline analyses"?
b. Should proposed Part 4.3 include forced Transmission and generation outages (*i.e.*, N-1-1)?
c. Should proposed Part 4.3 include planned outages (*i.e.*, all planned outages in the base case)?

☐ Yes
☐ No
Comments:

<u>Question 11</u>: With regard to proposed Part 4.3: The SDT used the term "realistic" as opposed to "expected" in order to perform sufficient assessment to identify potential stability risks. The SDT takes that position that "unrealistic" stressing scenarios may be more of an academic exercise to "break the system" and may not translate to actual operations preparedness. Is "realistic" transfer, Load and generation dispatch levels an adequate description or should more clarifying language be added, such as a reference to firm and non-firm transfers?

☐ Yes
☐ No
Comments:

<u>Question 12</u>: With regard to proposed Part 4.5: Current FAC-011-3 Part 3.1 requires that the study models include the entire RC Area. However, the SDT believes that it is not necessary for reliability that the entire RC Area is studied; instead, the area modeled may vary depending upon the facts and circumstances of the particular footprint or electrical area. Should Part 4.5 require the anything different for description of the study model used? If so, what should else be included and why?

☐ Yes
☐ No
Comments:

<u>Question 13</u>: With regard to proposed Part 4.5: The requirement specifically identifies Remedial Action Schemes (RAS), however other protective schemes (such as UVLS and UFLS) and their impact on stability performance were not included. Should the requirement specifically identify other types of protective schemes? If yes, please describe why.

☐ Yes
☐ No
Comments:

<u>Question 14</u>: With regard to proposed Part 4.6: Do you agree that the RC SOL Methodology should specifically address this issue?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs).	**<u>Background regarding existing standards *not* under revision by SDT:</u>** • <u>TOP-001-3 Requirements R12 and R14</u> **<u>Mapping to existing FAC standards under revision:</u>** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	

Question 15: Do you agree that the RC should continue to have a process to specify the multiple contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation?

☐ Yes
☐ No
Comments:

Question 16: The multiple contingencies referenced in Requirement R5 relate to those stability limitations established under Requirement R4, some of which may be IROLs, while others may not. The intent of SDT was to allow the RC flexibility in developing its RC SOL Methodology so that it can use the list of multiple Contingencies in a manner that is broader than solely for use in establishing IROLs. For example, the multiple Contingencies can be used by the RC in identifying the conditions referenced in Requirement R8. Additionally, the RC could use the multiple Contingencies in its OPA to identify potential instability and Cascading outages. Do you believe an additional requirement is necessary to specifically identify how an entity would implement the multiple Contingencies? If yes, please provide the specific language you propose for the requirement.

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.	SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Question 17: Do you agree that the RC SOL Methodology should be required to include *all* of the criteria included in proposed Parts 6.1 through 6.4? Do you believe there are additional criteria that are not currently included, but should be?

☐ Yes
☐ No
Comments:

Question 18: Should the criteria identified in proposed Parts 6.1 through 6.4 also include a minimum or maximum threshold? If so, what should the thresholds be, and why?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Question 19: Do you believe the IROL T_v definition should be modified to remove the 30 minute not-to-exceed time limit, and instead the specific time limit should be identified in the specific Reliability Standard requirement, as appropriate?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state,	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand.	• FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Question 20: Do you agree with the proposed approach for addressing this Real-time operating state issue?

☐ Yes

☐ No

Comments:

<u>Question 21</u>: Do you believe there should be a timing requirement for implementing actions to address the risk (*e.g.*, 30 min)? If yes, when should the time start? End?

☐ Yes
☐ No
Comments:

<u>Question 22</u>: Do you believe that this issue is already addressed in other Reliability Standards (*i.e.*, IRO-009 and EOP-011)? If not, should it be?

☐ Yes
☐ No
Comments:

<u>Question 23</u>: If the proposed requirement is added, should a reciprocal requirement be added to require implementation of the method (*e.g.*, possibly a new TOP or IRO requirement)?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R4</u> – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology; **9.2.** Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its RC Area; and, each TOP that operates in its RC Area.

<u>Question 24</u>: Do you agree with the proposed revisions? If not, please explain why and provide any changes that you propose to the language.

☐ Yes
☐ No
Comments:

Unofficial Comment Form for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

Before submitting comments with regard to the proposed changes to FAC-014-3, please review the background information section provided in the "Unofficial Comment Form for FAC-011-4." That document contains foundational information that must be reviewed in order to have a complete understanding of the proposed changes to FAC-014-3.

Proposed Revisions, Background Information and Questions

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 1: Do you agree with that the Reliability Coordinator (RC) should have primary responsibility for establishing IROLs for its RC Area? If not, please provide your comments on the appropriate break down of responsibilities (between RC and TOP) in establishing IROLs.

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 2: The proposed revisions work together with the proposed revisions to the definition of SOL. The new requirement makes clear that the TOP will establish SOLs in accordance with the RC SOL Methodology. This means that the TOP will follow the RC Methodology to determine: applicable Facility Ratings for use in operations (see, proposed FAC-011-4 Requirement R2); applicable steady-state System

voltage limits to be used in operations (see, proposed FAC-011-4 Requirement R3); and, the applicable stability limitations, if any, that are to be used in operations (see, proposed FAC-011-4 Requirement R4). Do you believe that it is clear that the TOP must establish SOLs in accordance with what is outlined in the RC Methodology?

☐ Yes
☐ No
Comments:

Question 3: TOP application of the RC Methodology will always result in identification of the appropriate Facility Ratings and steady-state System voltage limits, however, it may not always result in identification of stability limitations (this is *only if* there are no applicable limitations specific to the TOP). If there are appropriate stability limitations (identified as a result of implementing the RC method for determining the stability limitations in proposed FAC-011-4 Requirement R4), then the TOP will identify these SOLs. Do you believe this is clear from the language of the requirements (both in FAC-14-3 Requirement R2 combined with the proposed revisions to FAC-011)?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified	**<u>Mapping to existing FAC standards under revision:</u>** • <u>N/A</u>: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation	

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Question 4: Do you believe that the RC should be responsible for establishing stability limitations used in operations where more than one TOP is impacted?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.	dynamically determined Facility Ratings or stability limitations.	

<u>Question 5</u>: Do you agree that the RC should be the only entity responsible for providing other entities within its RC Area the established SOLs? If no, do you believe the entity that establishes the SOL (either the RC *or the TOP*) should be the entity that communicates the SOL to other entities? Please explain.

☐ Yes
☐ No
Comments:

<u>Question 6</u>: With regard to proposed Part 4.1: Do you believe that the language provides sufficient clarity regarding what is required for communicating updates to dynamically updated limits? If not, what language do you propose?

☐ Yes
☐ No
Comments:

<u>Question 7</u>: With regard to proposed Part 4.1: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the communications, or should the RC have flexibility in determining what is appropriate for its particular RC Area?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL. **5.2.** The value of the IROL and its associated IROL T_v. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 8: Do you agree with the information identified in Parts 5.1 through 5.4? Is there any additional information that the RC should provide regarding IROLs? Are there any additional entities that should be included in this requirement and receive the information from the RC?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed Reliability Standard: FAC-014-3, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	operator information not appropriate for open-ended sharing.	

Question 9: In consideration of the FERC directive regarding communicating IROL information to the Transmission Owner, do you agree with this proposed new requirement? If not, please explain the basis for why you do not support the proposed requirement, and the alternative language you are proposing to address the issues raised in FERC Order No. 777.

☐ Yes
☐ No
Comments:

Question 10: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the information to the Transmission Owner and Generator Owner?

☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share	The SDT did not make substantive changes to this requirement; however, the requirement previously existed	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
its portion of the Reliability Coordinator Area.	as a "part" of a requirement and it is now a stand-alone requirement.	and Transmission Service Providers in its portion of the RC Area.

Question: None.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP.	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
8.2. The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	

Question 11: Do you agree that there is a reliability-related need for the RCs and TOPs to obtain the information from the Planning Assessment and Transfer Capability analysis for the purpose of identifying instability risks when establishing SOLs (and IROLs)? Are there other "studies" that are currently performed that should also be included in this communication requirement?

☐ Yes

☐ No

Comments:

Question 12: Are there additional "studies" or activities that planners should undertake (beyond those currently required in the current standards, including TPL-001-4 and FAC-013-2) to identify instability risks? If so, please describe.

☐ Yes
☐ No
Comments:

<u>Question 13</u>:With regard to Part 8.3: The SDT believes that the information listed in Part 8.3 is critical for RC and TOP awareness and understanding of the instability risks identified in the planning horizon and the listed mitigation measures employed to address those risks. Do you agree? If not, please explain why you believe it is not critical that the RC and TOP obtain this information from the planning entities?

☐ Yes
☐ No
Comments:

<u>Question 14</u>: Do you agree that this proposed requirement is appropriately placed in FAC-014, or do you believe the proposed requirement should be placed in another standard (*i.e.*, TPL-001-4 and FAC-013-2)?

☐ Yes
☐ No
Comments:

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RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the [electronic form] to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the [project page]. If you have questions, contact Lacey Ourso, Standards Developer by [email] or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

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[1] *See*, TPL-001-4

[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3

[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1

[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of “the most limiting criteria,” “specified system configuration,” “operation within acceptable reliability criteria,” and “pre- and post-Contingency.” These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is “the most limiting.” Also, as detailed below, the definition of “SOL Exceedance” will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term “stability limitation” rather than “transient stability limit,” “voltage stability limit” or the Glossary term “Stability Limit.” The intent of the SDT is that “stability limitation” is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term “Stability Limits” is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)”

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • TOP-002-4 Requirement R1 - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• <u>IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3)</u> – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • <u>IRO-008-2, Requirement R1</u> – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • <u>MOD-001-2, Requirement R1 (Part 1.1)</u> – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-014-2, Requirement R6 (Parts 6.1 and 6.2)</u> – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R3.7</u>- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• <u>N/A</u>: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-014-2 Requirement R5</u> – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_v. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits | FAC-011-4 and FAC-014-3

Informal Comment Period Open through August 12, 2016

Now Available

A 30-day informal comment period for **FAC-011-4 System Operating Limits Methodology for the Operations Horizon and FAC-014-3 Establish and Communicate System Operating Limits,** is open through **8 p.m. Eastern, Friday, August 12, 2016**.

Commenting

Use the electronic forms to submit comments on the standards. If you experience any difficulties using the electronic forms, contact Nasheema Santos. Unofficial Word versions of the comment forms are posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The drafting team will hold a meeting on August 23-25, 2016 to review all responses received during the informal comment period, and revise the standards as needed based upon industry feedback.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Lacey Ourso (via email), or at (404) 446-2581.

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Comment Report

Project Name: Project 2015-09 Establish and Communicate System Operating Limits | FAC-011-4

Comment Period Start Date: 7/14/2016

Comment Period End Date: 8/12/2016

Associated Ballots:

There were 36 sets of responses, including comments from approximately 36 different people from approximately 34 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Given how the revisions are intended to work together with the revised TOP and IRO Reliability Standards (including the definitions of OPA, RTA and Operating Plan), do you agree with the proposed revisions to the definition of SOL and new definition of "SOL Exceedance"? If not, please explain why you do not support the revisions, and what revisions you propose to align the definition(s) with the revised TOP and IRO Reliability Standards.

2. The suggested revisions would mean that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. OPAs and RTAs are performed to determine whether these SOLs may potentially be exceeded (through an OPA) or are actually being exceeded (through a RTA). Operating Plans are developed to address "'SOL Exceedances." Do you believe the proposed revisions to the definition of SOL (and companion definition of "SOL Exceedance") allow for a clear distinction between "what the limits are" and "how the system should be operated"

3. Do you agree with removing "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post- Contingency" concepts from the definition of SOL? If no, please explain your concerns.

4. Do you agree that the TOP should determine the appropriate Facility Ratings for use in operations, in accordance with the requirements set in the RC SOL Methodology? Note: This assumes the Facility owner will continue to provide the Facility Ratings to the RC and TOP as currently required under FAC-008. The RC Methodology will simply describe the manner in which the TOP determines which of those owner-provided Facility Ratings are appropriate for use in operations.

5. Do you agree that the TOP should establish the System voltage limits pursuant to the RC SOL Methodology, and that the proposed Requirement R3 provides sufficient clarity for what the RC SOL Methodology must include?

6. Is it clear what System voltage limits are? Does a definition for "System Voltage Limits" need to be created? A draft definition under consideration by the SDT is "System Voltage Limits: The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations." Please provide your perspective on whether, currently, it is clear what is meant by System voltage limits, and if not, what you believe to be the appropriate definition.

7. Do you agree that the proposed use of the word stability "limitations" is a better choice than "limit" to capture the full breadth of all phenomena and determination methods/time frames for stability concerns?

8. With regard to proposed Part 4.1: Do you agree that the RC SOL Methodology should have criteria that consider *all* items in Parts 4.1.1 – 4.1.4? Are there additional criteria that should be included? If yes, please list and explain. Are there criteria that are included, that you believe should *not* be included?

9. With regard to proposed Part 4.2: Do you agree that the RC SOL Methodology should consider the contingencies listed in Parts 4.2.1 and 4.2.2? Are there additional Contingencies that should be included? If yes, please list and explain. Are there Contingencies that are included, but you believe should *not* be included?

10. With regard to proposed Part 4.3: When instability risks are identified, there are various studies or assessments that analyze different transfer levels, load levels and generation dispatch combinations. The intent of Part 4.3 is to ensure that the RC SOL Methodology adequately describes how these various factors are considered in the identification of instability risks. In the identification of stability risks, the RC SOL Methodology should consider the levels of transfers, load and generation dispatch. Should the RC SOL Methodology include a description of any additional types of information?

a. Should proposed Part 4.3 specifically include "offline analyses"?

b. Should proposed Part 4.3 include forced Transmission and generation outages (*i.e.*, N-1-1)?

c. Should proposed Part 4.3 include planned outages (*i.e.*, all planned outages in the base case)?

11. With regard to proposed Part 4.3: The SDT used the term "realistic" as opposed to "expected" in order to perform sufficient assessment to identify potential stability risks. The SDT takes that position that "unrealistic" stressing scenarios may be more of an academic exercise to "break the system" and may not translate to actual operations preparedness. Is "realistic" transfer, Load and generation dispatch levels an adequate description or should more clarifying language be added, such as a reference to firm and non-firm transfers?

12. With regard to proposed Part 4.5: Current FAC-011-3 Part 3.1 requires that the study models include the entire RC Area. However, the SDT believes that it is not necessary for reliability that the entire RC Area is studied; instead, the area modeled may vary depending upon the facts and circumstances of the particular footprint or electrical area. Should Part 4.5 require the anything different for description of the study model used? If so, what should else be included and why?

13. With regard to proposed Part 4.5: The requirement specifically identifies Remedial Action Schemes (RAS), however other protective schemes (such as UVLS and UFLS) and their impact on stability performance were not included. Should the requirement specifically identify other types of protective schemes? If yes, please describe why.

14. With regard to proposed Part 4.6: Do you agree that the RC SOL Methodology should specifically address this issue?

15. Do you agree that the RC should continue to have a process to specify the multiple contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation?

16. The multiple contingencies referenced in Requirement R5 relate to those stability limitations established under Requirement R4, some of which may be IROLs, while others may not. The intent of SDT was to allow the RC flexibility in developing its RC SOL Methodology so that it can use the list of multiple Contingencies in a manner that is broader than solely for use in establishing IROLs. For example, the multiple Contingencies can be used by the RC in identifying the conditions referenced in Requirement R8. Additionally, the RC could use the multiple Contingencies in its OPA to identify potential instability and Cascading outages. Do you believe an additional requirement is necessary to specifically identify how an entity would implement the multiple Contingencies? If yes, please provide the specific language you propose for the requirement.

17. Do you agree that the RC SOL Methodology should be required to include *all* of the criteria included in proposed Parts 6.1 through 6.4? Do you believe there are additional criteria that are not currently included, but should be?

18. Should the criteria identified in proposed Parts 6.1 through 6.4 also include a minimum or maximum threshold? If so, what should the

thresholds be, and why?

19. Do you believe the IROL Tv definition should be modified to remove the 30 minute not-to-exceed time limit, and instead the specific time limit should be identified in the specific Reliability Standard requirement, as appropriate?

20. Do you agree with the proposed approach for addressing this Real-time operating state issue?

21. Do you believe there should be a timing requirement for implementing actions to address the risk (*e.g.*, 30 min)? If yes, when should the time start? End?

22. Do you believe that this issue is already addressed in other Reliability Standards (*i.e.*, IRO-009 and EOP-011)? If not, should it be?

23. If the proposed requirement is added, should a reciprocal requirement be added to require implementation of the method (*e.g.*, possibly a new TOP or IRO requirement)?

24. Do you agree with the proposed revisions? If not, please explain why and provide any changes that you propose to the language.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Paul Mehlhaff	Sunflower Electric Power	1	SPP RE

						Corporation		
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company	6	SERC

						Generation and Energy Marketing		
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1,3,5,6	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Con Edison and ISO-NE	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC

					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					John Allen	City of Utilities of Springfield, MO	1,4	SPP RE
					Ron Losh	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Robert Hirchak	Cleco	1,3,5,6	SPP RE

1. Given how the revisions are intended to work together with the revised TOP and IRO Reliability Standards (including the definitions of OPA, RTA and Operating Plan), do you agree with the proposed revisions to the definition of SOL and new definition of "SOL Exceedance"? If not, please explain why you do not support the revisions, and what revisions you propose to align the definition(s) with the revised TOP and IRO Reliability Standards.

Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6, Group Name Con Edison	
Answer	No
Document Name	
Comment	

The proposed definition for the new term SOL Exceedance is too broad and would create and undue burden for TOPs notifying their RCs when the reporting threshold for an exceedance has been met. To align the definition of the new term with our RC's current SOL Methodology, we propose the following changes to the definition of SOL Exceedance:

"An operating condition characterized by any of the following:

-Actual or pre-Contingency flow on a Facility is above the Normal Rating, for the associated time frame

-Calculated post-Contingency flow on a Facility is above the highest Emergency Rating

-Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs

-Actual or pre-Contingency bus voltage is outside normal System voltage limits, for the associated time frame

-Calculated post-Contingency bus voltage is outside applicable system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occur

-Operating parameters indicate the next Contingency could result in instability."

The rationale for the changes is as follows. Actual thermal and voltage limits may have associated timeframes which, if not exceeded, do not compromise the integrity of the equipment or the BES. Also, the bullet "calculated post-Contingency bus voltage is outside the emergency system voltage limits" is redundant with the bullet "Calculated post-Contingency bus voltage is outside applicable system voltage limits…"

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	

The new definition of SOL is appropriate. The last bullet of the "SOL Exceedance" definition needs to limit the instability to BES facilities. Bullet 3 and bullet 6 of the SOL Exceedance definition should state, “should the Contingency occur” instead of “should the Contingency occurs.”	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS respectfully suggests that the last bullet in SOL Exceedance definition (Operating parameters indicate the next Contingency could result in instability) be clarified or deleted. AZPS agrees that the previous bullets thoroughly define what constitutes a SOL Exceedance in pre-, actual, and post- contingency conditions. However, the last bullet implies that, following a contingency, a system must immediately meet stability limits for the next contingency - even before system readjustments have been completed and even prior to the expiration of the Tv time period. This could create a contradiction and associated confusion relative to registered entity obligations within this reliability standard. . The phrase “stability limitation” is not a defined term and, to ensure consistent interpretation, should be defined.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Manitoba Hydro strongly believes that it is necessary to respect actual operating parameters such as Facility Ratings, System voltage limits and any known stability limitation in the real-time operating horizon. The new SOL definition is much clearer than the existing one. However, by including stability limitations in the definition of an SOL, it is much more difficult to differentiate between an SOL and an IROL based on the existing definition of an IROL. By their very nature, stability limits are determined to prevent instability, uncontrolled separation or cascading outages. Perhaps the IROL definition also needs revision to help determine which stability limitations warrant special IROL designation and more careful scrutiny. However, the standard tries to address the “special nature” of the IROL. The existing IROL definition is confusing in the context of all these other revisions.	

Manitoba Hydro does not support the proposed definition of SOL Exceedance for the following reasons.

1. Post contingency bus voltage and timing

It is difficult to differentiate between the following operating conditions:

-
    -
        - Calculated post-Contingency bus voltage is outside the emergency system voltage limits;
        - Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs;

It appears that this definition is meant to mirror system operating conditions associated with post-contingency facility ratings (second and third bullets in SOL exceedance definition). While emergency Facility Ratings can reflect a maximum mitigation timeframe to address a thermal rating overload to manage equipment loss of life, voltage limits are not dynamic in the same way. Adding the mitigation timeframe doesn't make sense in the context of voltage – it's just confusing.

1. Potential SOL exceedance and actual SOL exceedance

While Manitoba Hydro believes that it may be necessary to take some pre-contingency action to operate the power system in a secure manner, a potential SOL exceedance and an actual SOL exceedance are not the same and should not be treated in the same manner. For example, if real-time contingency analysis identified a potential SOL exceedance, it does not make sense to notify the RC. The utility can take preventive action to address the potential SOL exceedance. On the other hand, an actual SOL exceedance should be reported to the RC.

Under the fourth bullet of "Overview of the proposed revisions to FAC-011-3, FAC-014-2 and defined terms SOL and SOL exceedance" it says that "A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA". However, NERC glossary of term defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions…."

These two statements contradict each other. As described in the definition, RTA identify the actual SOL exceedance (corresponds to existing or pre contingency condition) and potential SOL exceedance (corresponds to post contingency condition). You've made a distinction here between the two time frames that is not reflected in the definition and requirements.

2. IROL exceedance Vs. SOL exceedance

Manitoba Hydro has concerns with the following bullet in the SOL exceedance definition:

- Operating parameters indicate the next Contingency could result in instability

Is this an SOL or an IROL? This operating condition is another reason to examine the IROL definition to add clarity.

Likes 0	
Dislikes 0	

Response

Robert Roddy - Dairyland Power Cooperative - 1,5

Answer	No
Document Name	

Comment

See MISO TOP-IRO Task Team response.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

The first bullet in the SOL Exceedance definition should take into account the timeframes and level of risk that the TOP has determined when defining SOLs in accordance with the RC's SOL Methodology. As currently written, the proposed definition for SOL Exceedance redefines SOL (i.e. System Operating Limits) from what the team is proposing for SOL. Note that the SOL definition imports all of the meaning of the defined terms used within the proposed SOL definition. The first bullet of the proposed SOL Exceedance definition ignores that flow can be above the Normal Rating of a Facility without being above the System Operating Limit (i.e. not an SOL Exceedance) since the condition being experienced could be a post-contingency condition where the amount of flow is within the relevant flow limit for a limited period of time. Suggested wording: “Actual or pre-Contingent flow on a Facility is above the applicable rating for longer than the allowable time frame for that Rating”. By similar argument, the same wording should be used for the fourth bullet: “Actual or pre-Contingent voltage on a Facility is outside the applicable voltage limit for longer than the allowable time frame for that voltage limit.” The fifth bullet should be removed as the sixth bullet correctly covers the time frame to resolve the bus voltage outside of the emergency voltage limits.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment	
NPPD supports the comments submitted by the MISO TOP-IRO Task Team. In addition we have the following comment: Recommend adding “as applicable” or some similar term after stability limits in the definition of System Operating Limit. Not all Facilities will have stability limits. In addition, stability limits can and do involve a set of Facilities and not just a single Facility. The definition must be flexible enough to recognize these nuances in the way stability limits are developed and utilized. The current definition is not clear. A situation where a Compliance Enforcement Entity is looking for stability limits for every facility to demonstrate compliance would be very cumbersome and should be avoided.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Definition of SOL: Duke Energy requests more clarification on the lack of inclusion/distinction between normal and emergency ratings in the proposed definition of SOL. This implies that if an entity had a 2 hour rating (long term emergency rating), and the entity was operating within that 2 hour rating, this would be an SOL, and based on the proposed definition SOL Exceedance, you would have exceeded the SOL. We think clarification as to whether the definition of SOL will includes only normal ratings, or both normal and emergency ratings would greatly increase clarity, and becomes more relevant when reviewing the proposed definition of SOL Exceedance. Definition of SOL Exceedance: Duke Energy questions the assertion made in the first bullet under the proposed definition of SOL Exceedance. The instance in which an Actual Flow exceeds a Normal Rating, should not be considered as an SOL Exceedance. An entity would have Emergency Rating that would cover this instance. Also, there may be some confusion on the difference between Actual and pre-Contingency used in bullets 1 & 4. We suggest replacing that language with “Actual Flow on a Facility”. We think the addition of the language “and pre-Contingency” is a relative term and confusing and doesn’t really add any clarity to the definition. We also suggest the drafting team consider reducing the definition of SOL Exceedance to the 1st and 4th bullets. We disagree with the assertion that calculations or computer models of instances that haven’t actually occurred yet should be considered as an SOL Exceedance. If the drafting team insists on including instances discovered by tools, calculations, or computer models, we suggest the team consider breaking the definition down into Actual and/or Potential Exceedances.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	

SOL Exceedance definition:

3rd bullet uses the term sufficient. This term is undefined and open to interpretation. Suggest re-phrasing to read: "…for which the flow cannot be reduced to acceptable levels within 30 minutes should the Contingency occur."

6th bullet also uses the term sufficient. Suggest rephrasing to read: "…for which the condition cannot be relieved within 30 minutes should the Contingency occur."

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No
Document Name	

Comment

System Operating Limits are not reliability limits. SOL Exceedance defines abnormal operating conditions that, although must be cleared, for the most part do not present a reliability problem. Suggest removing "Reliability" from the SOL definition.

The sixth bullet embellishes the wording of the fifth bullet by the addition of the words "…for which there is not sufficient time to relieve the condition should the Contingency occurs…". The fifth and sixth bullets are redundant, and only the sixth bullet is needed.

Suggest changing the wording in the bullets of SOL Exceedance from "flow on" to "flow through".

Likes 0	
Dislikes 0	

Response

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	No
Document Name	

Comment

We disagree with the proposed revision to the SOL definition. In particular, the removal of the "most limiting" language introduces additional challenges since each component of the definition (Facility Ratings, System voltage limits, and stability limitations) are now individually and simultaneously SOLs for a given facility. This introduces unintended complexities compared to the existing definition. The rationale that the current definition presumes an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL and the proposed definition somehow does not is incorrect. In order to determine any limit an analysis has to be done. Also, the notion that entities continuously assess system performance based on actual operating conditions for each of these components is incorrect as well. While some TOPs have implemented real time voltage stability analysis they are by far the exception. Also, real time transient stability analysis is even more rare. Requiring all TOPs to perform these assessments in real time through the SOL definition will cause undue burden on the industry. While we don't necessarily agree that the current definition needs to be changed we do think it could be simplified by tweaking the proposed language to: "System Operating Limits: The value (such as MW, Mvar, amperes, frequency, or volts) that is the most limiting of the known Facility Ratings, system voltage limits, and stability ratings for a Facility and/or a group of Facilities and system configuration".

We disagree with the proposed definition of SOL Exceedance. Proposed definition of SOL Exceedance does not align with the concept of SOL exceedance described in NERC white paper on SOL definition and exceedance clarification. Proposed definition does not factor in the legitimacy of Emergency Ratings. Emergency Ratings are designed to reliably support the flow for a defined time frame. Actual flow between the Normal and Emergency Rating should not be an SOL Exceedance unless the flow is not reduced to the normal rating within the time frame associated with the Emergency Rating. If all flow/voltage normal limit exceedances are treated as SOL Exceedances TOP-001-3 R15 will require the Transmission Operator to inform the RC of actions taken to return the System to within limits even when flows or voltages are within defined limits for acceptable timeframes. This will be detrimental to reliability since it will create unnecessary burden and distractions for the TOP and RC.

The SOL exceedance definition states" Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs". This criterion is not practical as it will require the operator to monitor and evaluate all post contingent flows which are above normal rating but below emergency rating and determine operating actions feasibility. This will create significant burned with very little or no reliability value. This criterion should be removed from the definition from SOL exceedance.

The criterion "Calculated post-Contingency bus voltage is outside the emergency system voltage limits" and "Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs" seem contradictory as one states post contingent bus voltage outside emergency system limit is SOL exceedance while other states that it is an SOL exceedance when there is not sufficient time to relieve the condition. The definition should only include one criterion which should state "Calculated post-Contingency bus voltage is determined to be outside emergency system voltage limits for a timeframe longer than the allowable timeframe associated with that limit during implementation of mitigating steps should the Contingency occurs".

The SOL Exceedance definition states:

- 'Actual or pre-Contingency bus voltage is outside normal System voltage limits'
- 'Calculated post-Contingency bus voltage is outside the emergency system voltage limits'.

This definition does not account for practical differences between the impacts of high voltage and low voltage limits. Equipment tripping as a result of high voltage is much different than voltage collapse. Exceeding high voltage limit may not necessarily risk the reliability of the system but may cause local equipment outage. The high voltage limit exceedance should be treated as SOL exceedance only if the contingency of equipment experiencing high voltage shows other potential SOL exceedances. Treating all high voltage normal limit exceedances as SOL Exceedances will require initiation of the Operating Plan to mitigate the SOL Exceedance which may require unnecessary actions such as opening other transmission lines which can create more severe operating challenges compared to having facilities experience voltages between normal and emergency limits.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
SRP agrees with the proposed definition of Sytem Operating Limit. SRP does not support the definition for SOL Exceedance as it does not allow for the timely operation in a contingency state where the "Calculated post-contingencyflow..." under this definition operators would be required to operate to an N-1-1 state.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE has several concerns with the proposed definition of System Operating Limit (SOL).

- “Reliability limits” is undefined. The prior definition contained values to be operated within which is preferable because of a consistent approach with compliance monitoring and enforcement. Texas RE is unaware of any confusion around SOLs and since the FACs were effective there have been little to no violations related to SOLs which some may argue is evidence that there is not confusion around this issue that the SDT purports on the part of industry and the ERO.

- Currently, the Standards appear to ignore Normal and Emergency Ratings (FAC-008-3) regarding Facility Ratings for Generator Owners. Texas RE is concerned this issue will be exacerbated by the proposed definitions and possibly allow more unreliable behavior. When an entity decides to create a new rating other than Normal or Emergency, which is done, there is not clarity on how this definition would be applied. Texas RE suggests only allowing Emergency and Normal Ratings to be defined and have those be different values (which unfortunately does not always occur and reliable operations suffer because of lack of clarity.)

- The explanation indicates SOLs are only used in the operating horizon. Although TPL-001-4 does not specifically address SOLs or IROLs, the studies performed in order to meet the Requirements of TPL-001-4 may identify stability limits and IROLs that are more limiting than the Facility Ratings. These studies will likely be more in-depth than an OPA or RTA, and will allow a better opportunity to stress the System in order to identify potential stability limits and IROLs. If the Planning Coordinator is not required to establish a criteria for identifying stability limits and IROLs (FAC-010-3), it is likely that these limits will not be identified or there will be inconsistencies across the Planning Coordinator Area in identifying the limits.

- Texas RE is concerned with eliminating FAC-010-3. All aspects of SOLs, as currently defined and proposed, will not be met by TPL-001-4 without supporting mechanism to recognize SOLs (as determined by FAC-010). Also, without an SOL methodology for the planning horizon (FAC-010-3), there may be inconsistencies in steady state voltage limits across the Planning Coordinator Area, as TPL-001-4 R4 indicates the TP and PC are allowed to independently specify criteria for steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System.

Texas RE suggests the SDT consider the following:

- If the Planning Coordinator (PC) is no longer required to have an SOL methodology, it is unlikely that the PC will identify IROLs. Does this mean that elements of an IROL are no longer applicable in FAC-003-4 since they were not identified by the PC?
- The Applicability section 4.1.1.3 of CIP-014 includes Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. If the PC and TP are no longer required to identify IROLs, does this mean that these Facilities will not be identified as applicable until a real-time IROL is identified? If so, the implementation of physical security measures may not be completed for years after the IROL is identified.

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] We have a concern that the proposed definitions do not consider whether 'calculated' post-contingency values are valid or not. The concern is that if the calculated value is found to not be valid (possibly used incorrect input data), then there may not be an actual 'exceedance'. We also wish to point out that IRO-018/TOP-010 have requirements related to quality of RTA. However, those two standards do not apply to OPA. As written, the proposed definitions may lead to 'bad' OPA/RTA results being considered exceedances. Some guidance should be given that identified exceedances should be validated as real at some point in the identification process and then once found to be real, then labeled officially as an exceedance. Our concern is also related to the obligation in reporting from TOP-001-3 R15.

We also request some further guidance on the last bullet on the proposed SOL exceedance definition. We are concerned it may lead to an interpretation that there is a requirement to have 'online stability tools' in order to adequately be determining whether or not SOLs are being exceeded. We understand the bullet to apply to those who DO have online stability tools, and have an indicated exceedance as well as those who may have an 'unsolved' RTCA contingency. Does the team support the concept that an entity may be able to only evaluate stability against any stability limits previously identified from their TPL studies, rather than being required to have online stability analysis?

It is still not clear to us when exceedances that are in the process of being mitigated or exceedances above the highest limit available cross the line into 'compliance violation' territory. We understand the requirements in TOP/IRO regarding how we are supposed to have a plan, and then implement the plan. However at some point some situations would require load shed that the entity may elect not to shed pre-contingent. How long is acceptable for an entity to be in an exceedance situation above the highest limit before it becomes a compliance issue?

We also wanted to point out that there is a typo in the proposed SOL Exceedance definition. The last word in a couple of the bullets is "occurs". This should be changed to "occur".

We also have a concern that now with 'exceedance' being broadened to include possibly more issues, the volume of necessary data collection/logging could be significant. We ask the team to consider any impact to reliability by requiring operators to now further increase gathering proof of implementing Operating Plans for each and every exceedance. RTCA runs very frequently (10 times per hour) and may have several new issues come in and out.

Also, what is the team's thinking in regard to needing to log when a flow is drifting above and below the established limit, but very minimally. For example the post-contingent calculated flow hovering near the Emergency limit +/- a few MW's. Do we need to be concerned about capturing those

instances in the consideration of ‘zero tolerance’?	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA agrees with the broad intent for definition of SOL Exceedance, but WAPA would official request the SDT draft language regarding:

1) Definition of an SOL Violation, e.g. Is an SOL Violation = Actual flow above the highest posted rating exceeding the associated time limit?

2) From the material it was stated a Calculated Post-Contingent Exceedance identified in an OPA (one of more days out) is a potential SOL Exceedance that may need an Operating Plan? But it is not clear in the Standard that interpretation is the case. To that point reiteration of the process for an RTA may be helpful to Industry, as RTA inherently implies a process to validate system conditions and results. It would appear that a “post-Contingency flow or System Voltage calculated as part of the valid analysis supporting the RTA” would qualify as an SOL Exceedance for bullets 2,3,4 and 5.

2) Add BES to the definition. In light of the “Approved” edits to TOP-001-4 it would be beneficial to be explicit.

3) Change Bus Voltage to System Voltage.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We do not agree with the proposed definition because it lends itself to confusion between the limit and the performance criterion.

For example, new requirement 4.2 states that the SOL methodology shall:

“Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies”

In this requirement, what is the difference between “stability limitations” and “BES performance criteria”? As an example, is the statement “transient voltage dip must not be lower than 0.8 pu” a BES performance criteria or a stability limitation.

We do not agree with the proposed new definition of SOL exceedance. Specifically, we believe there are two sets of duplicated conditions:

First Set (Bullets 2 and 3):

- **Calculated post-Contingency flow on a Facility is above the highest Emergency Rating.**
- **Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occur.**

We believe the definition needs only to present the second bulleted condition since the first condition does not say whether or not there is sufficient time to reduce the flow to acceptable levels. If there is sufficient time, then it's not an exceedance (i.e., not the condition presented in the next bullet). If there isn't sufficient time, then it is duplicating the next bullet. We therefore suggest removing the first bulleted condition.

Second Set (Bullets 5 and 6):

- **Calculated post-Contingency bus voltage is outside the emergency system voltage limits.**
- **Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs.**

Our comment and suggestion are similar to the above (for the first set).

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

We have a concern that the proposed definitions do not consider whether 'calculated' post-contingency values are valid or not. The concern is that if the calculated value is found to not be valid, then there may not be an actual 'exceedance'. We also wish to point out that IRO-018/TOP-010 have requirements related to quality of RTA. However, those two standards do not apply to OPA. As written, the proposed definitions may lead to 'bad' OPA results being considered exceedances. Some guidance should be given that identified exceedances should be validated as real at some point in the identification process and then once found to be real, then labeled officially as an exceedance. Our concern is also related to the obligation in reporting from TOP-001-3 R15.

We also request some further guidance on the last bullet on the proposed SOL exceedance definition. We are concerned it may lead to an interpretation that there is a requirement to have 'online stability tools' in order to adequately be determining whether or not SOLs are being exceeded. We understand the bullet to apply to those who DO have online stability tools, and have an indicated exceedance as well as those who may have an 'unsolved' RTCA contingency. Does the team support the concept that an entity may be able to only evaluate stability against any stability limits identified from their TPL studies, rather than being required to have online stability analysis?

It is still not clear to us when exceedances that are being mitigated, or exceedances above the highest limit available cross the line into 'compliance violation' territory. We understand the requirements in TOP/IRO regarding how we are supposed to have a plan, and then implement the plan. However at some point some situations would require load shed that the entity may elect not to shed pre-contingent. How long is acceptable for an entity to be in an exceedance situation above the highest limit before it becomes a compliance issue.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

NIPSCO agrees with comments submitted by the MISO TOP-IRO Task team. NIPSCO believes the proposed definition by the MISO TOP-IRO Task Team provides a definition for SOL Exceedance based on the way the system is designed, engineered and operated. NIPSCO would also like point out an inconsistency withEOP-004 (which is effective at this time). In EOP-004 a voltage deviation on a facility is defined as reportable in Requirement 1 which refers to Attachment 1.   On page 9 of the standard, attachment 1 defines a voltage deviation on a facility as: "TOP Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes." The time frame is not included in any of the proposed definitions. Does anyone feel there is a problem with reporting a voltage deviation as part of EOP-004 but not in the SOL definition? This seems like an inconsistency that needs to be addressed possibly by the SDT. NIPSCO feels the time frame should be removed from EOP-004 and a reference the SOL exceedance added.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. We agree with the definition of SOL. We agree with much of the definition of SOL Exceedance. However, the definition does not account for Operator action. For example – “Actual or pre-Contingency flow on a Facility is above the Normal Rating” does not factor in the legitimacy of Emergency Ratings. Emergency Ratings are designed to reliably support the flow for a defined time frame. Actual flow between the Normal and Emergency Rating should not be an SOL Exceedance unless the flow is not reduced to the normal rating in the time frame used to develop the Emergency Rating, i.e. 15 minutes, 30 minutes, etc.
2. We have a concern that the proposed definitions also fail to consider whether ‘calculated’ post-contingency values are valid or not. If the calculated value is found to not be valid, then there may not be an actual ‘exceedance’. We also wish to point out that IRO-018/TOP-010 have requirements related to quality of RTA. However, those two standards do not apply to OPA. As written, the proposed definitions may lead to ‘bad’ OPA results being considered exceedances. Some guidance should be given that identified exceedances should be validated as real at some point in the identification process and then once found to be real, then labeled officially as an exceedance. Our concern is also related to the obligation in reporting from TOP-001-3 R15.
3. Guidance on the last bullet on the proposed SOL exceedance definition is needed. We are concerned it may lead to an interpretation that there is a requirement to have ‘online stability tools’ in order to adequately be determining whether or not SOLs are being exceeded. We understand the bullet to apply to those who DO have online stability tools, and have an indicated exceedance as well as those who may have an ‘unsolved’

RTCA contingency. Does the SDT team support the concept that an entity may be able to only evaluate stability against any stability limits identified from their TPL studies, rather than being required to have online stability analysis?

4. It is still not clear to us when exceedances that are being mitigated, or exceedances above the highest limit available cross the line into ‘compliance violation’ territory. We understand the requirements in TOP/IRO regarding how we are supposed to have a plan, and then implement the plan. However, at some point some situations would require load shed that the entity may elect not to shed pre-contingent. How long is acceptable for an entity to be in an exceedance situation above the highest limit before it becomes a compliance issue?

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern believes that the bulleted items of the proposed new SOL Exceedance definition should be included in the proposed definition of System Operating Limits. Our concern is that every time we have a OPA contingency analysis that identifies a contingency overload that is greater than the emergency rating of a facility, it would be declared at that time as an actual SOL Exceedance. We believe this condition should not be part of the definition of SOL Exceedance. Southern suggests a third definition, “Potential SOL Exceedance”.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	No
Document Name	

Comment

We would note that the SDT is presented with considerable challenges to address in this project and are grateful for the opportunity to offer our comments, which are shared with the greatest respect and appreciation for the work of the SDT.

We address our concerns and offer suggestions, below, to address: Proposed SOL Exceedance term; Measurable Compliance Thresholds; Consideration of Risk; Applicability; and a Practical Suggestion.

Exceedance: The word “exceedance” is used throughout the Reliability Standards, including Standards that incorporate the definitions for OPA, SOL, and IROL. As noted in the Project 2015-09 System Operating Limits Technical Conference Background Materials (TCBM), referencing “SOL Exceedance White Paper” (SOLEWP) section, “SOL Definition and Exceedance Clarification” (See TCBM, pp. 5-9), the proposed SOL Exceedance definition attempts to align with how the word “exceedance” is used throughout the Standards and to add clarity. The use of “exceedance” as proposed suggests something that may or may not represent noncompliance and, therefore, creates what it seeks to solve, ambiguity and a lack of clarity.

Background. “Exceedance” is used in Standards and in conjunction with OPAs, SOLs and IROLs; it also informs associated Violation Severity Level

(VSL) descriptions. The Project 2014-03 SOLEWP seeks to characterize SOL exceedance as, "…unacceptable system performance as indicated by Real-time Assessments [equating] to SOL exceedance." (SOLEWP, p.7). The SOLEWP continues by identifying unacceptable system performance with scenarios which are now incorporated, in some form, as part of the proposed SOL Exceedance definition. The elements listed in the proposed SOL Exceedance definition, if accepted, create a compliance threshold. We believe compliance thresholds should be unambiguous and clearly identify, as in this case, a given system condition that consistently, without waver, represents either compliance or noncompliance. However, the scenarios do not necessarily represent system conditions that provide a consistent, without waver, determination of either compliance or noncompliance. For example, the proposed SOL Exceedance condition, no. 7, does not contemplate there are contingencies that can cause "unit instability (local)" that would not cause "System instability (regional)". This situation would likely fall within condition no. 7 but is not an instance of noncompliance.

Discussion. The use of "exceedance" as proposed—SOL Exceedance—muddies compliance obligations and creates an unmeasurable threshold for compliance when considering how "exceedance" is already used throughout the Standards and used to create a compliance threshold.

The dictionary definition of "exceedance" supports that a limit is traversed, which is how the word is already used throughout the Standards. The proposed elements for the definition of SOL Exceedance characterize conditions of the BES but may not necessarily represent going over a material limit that impacts the BES.

Suggestion: Alternative Term for SOL Exceedance. Since the proposed term, SOL Exceedance, will be used to identify conditions that will determine issues of compliance and, yet, does not establish a clear compliance threshold, we respectfully encourage the use of another term. We recognize that would be a bold stroke for the SDT and, while not perfect substitutions, offer the following alternative terms:

"SOL States", "SOL Elements", "SOL Factors", "SOL Operating Conditions"

Other Issues

Measurable Compliance Thresholds. The current proposed SOL Exceedance definition does not offer clear and measurable thresholds to establish compliance obligations. The current language provides a characterization of the operating system and incorporates an interpretation, to determine limits, from, for all intents and purposes, FAC-011-2.

Suggestion: Do not add a SOL Exceedance definition and incorporate the operating conditions from the proposed definition into the TOP-002 or TOP-007 Standards to establish the operational compliance thresholds.

Consideration of Risk. There are occasions when the State Estimator and the Real-time Contingency Assessment produce invalid results. Also, actual and calculated conditions can oscillate just below and just above a limit and, when considered with TOP-007, necessitate continuous reporting to the RC. Invalid results and oscillating conditions beg the question, "What is really necessary to report to the RC to maintain the reliability of the BES?"

When we think about the fact freeway traffic routinely drives above the speed limit without accidents, does an exceedance on the BES that is only 0.1% really represent a reliability risk substantial enough to require reporting?

Granted, operating the BES is not like traffic on a freeway but the analogy highlights that whatever the definition or characterization of operating conditions of the BES is used, consideration of the risk of unfavorable impacts to the BES needs to be a part of the equation.

Suggestions: To highlight consideration of risk, we offer the following:

Add the word "valid" before "post-Contingency" in the proposed SOL Exceedance definition, as provided, below.

Also, while not a risk issue, the instability referenced in condition no. 7 can only be inferred. We suggest adding the NERC Glossary term, "System," before "instability" to clarify the object of the instability.

SOL Exceedance: An operating condition characterized by any of the following:

1. Actual or pre -Contingency flow on a Facility is above the Normal Rating
2. Calculated **valid** post -Contingency flow on a Facility is above the highes
3. Calculated **valid** post -Contin

acceptable levels should the Contingency occurs

4. Actual or pre -Contingency bus voltage is outside normal System voltage limits

5. Calculated **valid** post -Contingency bus voltage is outside the emergen

6. Calculated **valid** post -Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs

7. Operating parameters indicate the next Contingency could result in **System** instability.

Suggestion: The proposed SOL Exceedance definition is, for the most part, without limitation. In further consideration of risk and the evaluation of the impact on BES reliability versus the compliance burden, we would suggest an engineering study, or some form of empirical analysis, to potentially establish a range to the applicability of the SOL Exceedance definition. For example, the study or data may determine applying the definition to Facilities under 200kV offers little benefit to increasing reliability and carries a high cost. Also, if such a change was made, that the applicability would continue to be evaluated as experience is gained operating within the limits to ensure reliability had not been unfavorably impacted.

Practical Suggestion. Recognizing the standards' formatting guidelines may be driving the format of the proposed SOL Exceedance term, we would offer replacing bullet points with numbers or letters, making it easier to cite to a particular element in the definition.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	No
Document Name	

Comment

The drafting team should make a stronger distinct between ratings and limits. Every piece of equipment has a rating, thermal, voltage, frequency that is defined to protect the equipment from damage. The system is operated to limits that are determined by OPA's, RTA's. Limits may also be determined by a stability condition, transient or equipment stability. Operators are responsible for operating to the most limiting of conditions determined through the OPA's and RTA's. The propose definitions have lost the concept of a 'safe operating region' by removing the reference to most limiting condition. This concept should be revisited in the current standards or captured in the IRO and TOP Standards.

We recommend a change to the proposed SOL definition to include the following concepts:

System Operating Limits:

Reliability limits used for operations to meet acceptable BES performance,

identified through OPA's and RTA's,

from facility ratings that include thermal, voltage and frequency ratings,

that result in transfer Limits, system voltage limits, and stability limitations	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - MISO TOP-ISO Task Team - 1,2 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	

The MISO TOP-IRO Task Team disagrees with the definition of SOL. In particular, the removal of the "most limiting" language introduces additional challenges since each component of the definition (Facility Ratings, System voltage limits, and stability limitations) are now individually and simultaneously SOLs for a given facility. The notion that entities continuously assess system performance based on actual operating conditions for each of these components is incorrect as well. While some TOPs have implemented real time voltage stability analysis they are by far the exception. Also, real time transient stability analysis is even more rare. Requiring all TOPs to perform these assessments in real time through the SOL definition will cause undue burden on the industry. While we don't necessarily agree that the current definition needs to be changed we do think it could be simplified by tweaking the proposed language to: "System Operating Limits: The value (such as MW, Mvar, amperes, frequency, or volts) that is the most limiting of the known Facility Ratings, system voltage limits, and stability ratings for a Facility and/or a group of Facilities and system configuration".

In addition we cannot see how the SOL Exceedance definition can be made clear without relating it to "pre- and post- Contingency" concepts.

We do not agree with the definition of SOL Exceedance.

The SDT proposed definition of the SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency risk of SOL exceedance. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of Exceedances should be similar.

The actual, pre-contingency SOL Exceedance is a real-time condition exceeding the equipment's rated capabilities, while the calculated, post-contingency risk of SOL Exceedance requires another event to happen in order to become real and actual issue. It is clear that both of these types of exceedances require some control action to be implemented, but they might be treated differently in terms of urgency and severity of mitigating control actions, as they have different repercussions on system reliability. However, the distinction between the actual, pre-contingency SOL Exceedance and the calculated, post-contingency risk of SOL Exceedance has to be recognized in the definition, so that misconceptions that are incorporated in the definition do not subsequently cause confusion and inadequate response from real-time personnel in control centers.

In addition the proposed SDT SOL Exceedance definition does not factor in the collaboration on the RC and TOP in development of joint operating guides and in particular post contingency action plans.

The MISO TOP-IRO task team recommends a definition for SOL Exceedance that better reflects the difference in actual, pre-contingency SOL Exceedance, and the calculated, post-contingency risk of SOL Exceedance, which allows flexibility for TOPs and RCs to manage post-contingency risk of exceeding an SOL while taking operating actions to address that risk. As long as a post-contingent action plan exists or is agreed upon by the TOP and RC, the calculated, post-contingency risk of SOL Exceedance would not be considered as an SOL Exceedance. Our proposed definition of SOL Exceedance follows.

A. SOL exceedance identified in real-time monitoring (pre-contingency) based on real time system conditions

· Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.

· Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.

· Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

· Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for any time period.

· Any established Stability Limit (non-IROL) is exceeded for longer than 30 minutes or defined by Operating Plan.

B. SOL exceedance identified in the real-time assessment based on Post Contingent system conditions

· Projected Post Contingent Flow on a BES Facility > highest Emergency Rating and no specific post-contingency action plan agreed upon by TOP and RC. The post-contingent action plan must address potential impacts were the contingency to occur prior to normal congestion management procedures returning projected Post Contingent Flow within the highest Emergency Rating.

· Projected Post Contingent voltage on a BES facility< emergency low voltage limit and no specific post-contingency action plan developed by TOP or RC to address potential impacts were the contingency to occur..

Also, we do not agree that "Actual or pre-Contingency flow on a Facility above the Normal Rating" and "Actual or pre-Contingency bus voltage outside normal System voltage limits" are SOL exceedances. In both cases, we recommend use of Emergency Rating as opposed to Normal Rating, and have reflected this in the proposed definition of SOL Exceedance above. The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses no reliability repercussions as long as the flow on facility or voltage in the bus is returned below normal rating during time that was assigned for the emergency rating. In the matter of fact, this is one of main reasons that transmission operators are given an emergency ratings and that fact should be correspondingly recognized in the SOL exceedance definition.

We disagree with the bullets 3 and 6 in the SDT proposed definition due to use of the term "sufficient time to relieve the condition should the Contingency occurs". We believe that the fundamental principle of the SOL Exceedance definition should be that it is clear, simple and understandable to transmission operators and RCs in control center. It will be quite challenging task for operators to determine "sufficient time" especially for those exceedances that occur suddenly due to unforeseen and not previously analyzed system conditions or after forced outages. Furthermore, this part of the SDT's proposed definition of SOL exceedances is currently being addressed by emergency operations in operating plans of TOPs. In other words, if TOPs realize, during real-time events, that the flow on facility would not be able to be returned below normal rating within the time assigned for emergency rating, TOPs would implement emergency control actions such as load shedding or generator tripping. Therefore, these types of issues do not need to be separately included into the SOL exceedance definition, and have been removed from our proposed definition of SOL Exceedance above.

Finally we disagree with treating high and low voltage the same in the SOL Exceedance definition. The definition does not account for practical differences between the impacts of high voltage and low voltage limits. Equipment tripping as a result of high voltage is much different than voltage collapse. Usually occurring at low loads and low transmission loading, exceeding high voltage limit may not necessarily risk the reliability of the system but may cause local equipment outage

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	2015-09_FAC-011-4 - Comment Form Questions - TOP-IRO TT response to Q 1 - 3 Aug 11..docx

Comment

The MISO TOP-IRO Task Team disagrees with the definition of SOL. In particular, the removal of the "most limiting" language introduces additional challenges since each component of the definition (Facility Ratings, System voltage limits, and stability limitations) are now individually and simultaneously SOLs for a given facility. The notion that entities continuously assess system performance based on actual operating conditions for each of these components is incorrect as well. While some TOPs have implemented real time voltage stability analysis they are by far the exception. Also, real time transient stability analysis is even more rare. Requiring all TOPs to perform these assessments in real time through the SOL definition will cause undue burden on the industry. While we don't necessarily agree that the current definition needs to be changed we do think it could be simplified by tweaking the proposed language to: "System Operating Limits: The value (such as MW, Mvar, amperes, frequency, or volts) that is the most limiting of the known Facility Ratings, system voltage limits, and stability ratings for a Facility and/or a group of Facilities and system configuration".

In addition we cannot see how the SOL Exceedance definition can be made clear without relating it to "pre- and post- Contingency" concepts.

We do not agree with the definition of SOL Exceedance.

The SDT proposed definition of the SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency risk of SOL exceedance. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of Exceedances should be similar.

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In addition the proposed SDT SOL Exceedance definition does not factor in the collaboration on the RC and TOP in development of joint operating guides and in particular post contingency action plans.

The MISO TOP-IRO task team recommends a definition for SOL Exceedance that better reflects the difference in actual, pre-contingency SOL Exceedance, and the calculated, post-contingency risk of SOL Exceedance, which allows flexibility for TOPs and RCs to manage post-contingency risk of exceeding an SOL while taking operating actions to address that risk. As long as a post-contingent action plan exists or is agreed upon by the TOP and RC, the calculated, post-contingency risk of SOL Exceedance would not be considered as an SOL Exceedance. Our proposed definition of SOL Exceedance follows.

1. **SOL exceedance identified in real-time monitoring (pre-contingency) based on real time system conditions**

- Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.
- Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.
- Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.
- Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for any time period.
- Any established Stability Limit (non-IROL) is exceeded for longer than 30 minutes or defined by Operating Plan.

2. **SOL exceedance identified in the real-time assessment based on Post Contingent system conditions**

- Projected Post Contingent Flow on a BES Facility > highest Emergency Rating and no specific post-contingency action plan agreed upon by TOP and RC. The post-contingent action plan must address potential impacts were the contingency to occur prior to normal congestion management procedures returning projected Post Contingent Flow within the highest Emergency Rating.

- Projected Post Contingent voltage on a BES facility< emergency low voltage limit and no specific post-contingency action plan developed by TOP or RC to address potential impacts were the contingency to occur..

Also, we do not agree that “Actual or pre-Contingency flow on a Facility above the Normal Rating” and “Actual or pre-Contingency bus voltage outside normal System voltage limits” are SOL exceedances. In both cases, we recommend use of Emergency Rating as opposed to Normal Rating, and have reflected this in the proposed definition of SOL Exceedance above. The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses no reliability repercussions as long as the flow on facility or voltage in the bus is returned below normal rating during time that was assigned for the emergency rating. In the matter of fact, this is one of main reasons that transmission operators are given an emergency ratings and that fact should be correspondingly recognized in the SOL exceedance definition.

We disagree with the bullets 3 and 6 in the SDT proposed definition due to use of the term “sufficient time to relieve the condition should the Contingency occurs”. We believe that the fundamental principle of the SOL Exceedance definition should be that it is clear, simple and understandable to transmission operators and RCs in control center. It will be quite challenging task for operators to determine “sufficient time” especially for those exceedances that occur suddenly due to unforeseen and not previously analyzed system conditions or after forced outages. Furthermore, this part of the SDT’s proposed definition of SOL exceedances is currently being addressed by emergency operations in operating plans of TOPs. In other words, if TOPs realize, during real-time events, that the flow on facility would not be able to be returned below normal rating within the time assigned for emergency rating, TOPs would implement emergency control actions such as load shedding or generator tripping. Therefore, these types of issues do not need to be separately included into the SOL exceedance definition, and have been removed from our proposed definition of SOL Exceedance above.

Finally we disagree with treating high and low voltage the same in the SOL Exceedance definition. The definition does not account for practical differences between the impacts of high voltage and low voltage limits. Equipment tripping as a result of high voltage is much different than voltage collapse. Usually occurring at low loads and low transmission loading, exceeding high voltage limit may not necessarily risk the reliability of the system but may cause local equipment outage

Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team. Additionally, we don't believe that every facility limit is an SOL nor is reaching a normal rating of a facility is an SOL exceedance. A different term is needed for this.	
Likes 0	

Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

We ask the drafting team for the rationale in the proposed new definition of SOL exceedance. We believe there are two sets of duplicated conditions:

First Set (Bullets 2 and 3):

- **Calculated post-Contingency flow on a Facility is above the highest Emergency Rating**
- **Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occur**

What is the intent of the second bulleted condition since the first condition does not say whether or not there is sufficient time to reduce the flow to acceptable levels? If there is sufficient time, then it's not an exceedance (i.e., not the condition presented in the next bullet). If there isn't sufficient time, then it is duplicating the next bullet.

Since some TOs may provide more than just the Emergency Rating, which can be a 5-minute rating or a 15-minte rating for a transmission line could the term "Emergency Rating" be better stated as "applicable rating"? A TO may also provide 30-minute rating, or 1-hour or 4-houir rating, and requests the TOP and/or the RC to apply the 30-minutes or 1-hour rating (hence the applicable rating). In this case, if and when a contingency occurs, the TOP needs to return loading of the facility to within the applicable rating, NOT the emergency rating. The applicable rating (NOT the Emergency Rating) thus sets the limitation for the calculation of SOL.

Second Set (Bullets 5 and 6):

- **Calculated post-Contingency bus voltage is outside the emergency system voltage limits**
- **Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs**

Our comment and suggestion are similar to the above (for the first set).

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment

The following answers for all questions 1 - 24 are provided by our City Light SMEs. After the submittal, the SMEs asked to make some additional changes to the original submittal. If yes/no vote changed I placed it in the comment section. Thank you.

The new definitions appear to be superior to the old versions, but we still have some comments:

1. The new SOL definition includes Facility Ratings and Voltage Limits as separate items. I think this is appropriate, but elsewhere in this document, it is stated plainly several times that the drafters expect that FAC-008-3 Facility Ratings should include voltage ratings. I have never seen voltage ratings included with FAC-008-3 ratings and the standard (including the definition of “Facility Ratings”) is not clear on whether it is required. There should be some effort to clarify where the responsibility for developing voltage limits lies, although depending on the desired direction, this may have to be in FAC-008 and not in this standard.

2. In the SOL Exceedance definition, the third bullet says “a Facility Rating” where the term “Emergency Rating” seems more appropriate. “Emergency Rating” is used in the explanation for that bullet item and in the parallel item for voltage limits (sixth bullet) the term “emergency system voltage limits” is used.

3. Including Bullet #1 in the SOL Exceedance definition may restrict TOP operations. It would require a TOP to report exceeding a SOL for instances where a facility exceeded its normal SOL but was less than emergency time SOL for even a few scan cycles. Currently, this is not considered “unacceptable system performance.” Recommend the following wording for Bullet #1:

**Actual or pre-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow below the Normal Rating.*

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	

Comment	
However, in the SOL Exceedance definition, we are unable to appreciate the distinction between bullet 5 (outside the emergency system voltage limits) and bullet 6 (outside the emergency system voltage limits for which there is not sufficient time to relieve the condition) - please provide a more detailed explanation of the intended difference between them.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Within the SOL Exceedance definition, the 4th bullet refers to "System voltage limits" while the 5th bullet refers to "system voltage limits". Consistent capitilzation suggested.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

We would like to acknowledge the great effort and work of the SDT in improving the SOL related standards and we support the new definitions of SOL and SOL Exceedance. We would like to point out the following for consideration by the SDT.

1- Concerning the language "sufficient time to …" in bullets 3 and 6, it is unclear how the "time evaluation" to address the issue needs to be managed in real time when actual system conditions may vary from the day-ahead OPA and Operating Plan used to mitigate the SOL Exceedance. We understand and agree that the day-ahead OPA may identify a "time to relieve the condition" that exceeds the allowed time to respect the Facility Rating or voltage limit, but in real-time the actual availability of resources and time to complete the operating actions may vary widely. For example, what happens if the time to get the appropriate reactive resources available to mitigate a voltage-related SOL is different in real time from what was planned in the OPA? How often does the "sufficient time" need to be evaluated in real-time by the TOP to take the decision of treating a SOL Exceedance (initiate an Operating Plan before the contingency actually occurs)?

2- There is confusion between bullets 5 and 6, both addressing the post-Contingency bus voltage outside the emergency limits. In particular, bullet 6 is logically redundant to bullet 5.

3- Concerning the last bullet, "Operating parameters indicate the next Contingency could result in instability", we understand that the intent is to capture all the possible stability limitations that could be identified in real-time. However, since industry practice includes a good proportion of “maximum MW transfer” on equipment and interfaces to manage stability constraints (often with offline studies), it would seem appropriate to add a separate bullet (or at least some additional rationale) to clearly state that “Pre-Contingency flow on an interface exceeds the identified stability limit” constitutes an SOL Exceedance. There are 3 bullets to address Facility Ratings, thus it would make sense to be more explicit on stability related SOLs.

4- In terms of the SOL definition itself – Assuming all limits are Facility Ratings, Systems voltage limits and stability limitations, the definition can be aligned more closely with the purposes of the standards and avoid the use of the ambiguous “Reliability limit”– i.e. “SOL - Facility Ratings, System voltage limits and stability limitations relevant for the reliable operation of the BES” or perhaps “Limits relevant to the operation of the BES arising from Facility Ratings, System voltage limits and stability limitations”.

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	

The revised definition of SOL is good. The SDT might consider using “Stability Limits” in the definition and then revising the definition of Stability Limits in the NERC glossary so that it goes well with this definition of SOL. The stability limitations language in the current definition can work but it may lead to some confusion.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

- BPA recommends the following language be added to the first bullet of the SOL Exceedance definition: “Actual or pre-Contingency flow on a Facility is above the Normal Rating *****for more than (X) minutes, as defined in the TOP’s Operating Plan***.”

- BPA also recommends the following language be added to the fourth bullet of the SOL Exceedance definition: “Actual or pre-Contingency bus voltage is outside normal System voltage limits *****for more than (X) minutes, as defined in the TOP’s Operating Plan.”***

Many times in operations, a facility may exceed its Normal Rating for two minutes and then resolve below the Normal Rating. BPA believes this additional language would prevent the potential need for a TOP to document and/or report every occurrence of operating above the Normal Rating.

From a pragmatic perspective, this language would eliminate a potential resource burden to complete a compliance reporting task that does not enhance reliability. (**As noted by the SDT in paragraph 1 in the explanation column of 'Proposed New Definition of SOL Exceedance' table.)	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
The two post contingency bus voltage bullets seem to be in disagreement. The first says an exceedance is if you are outside the voltage limits. The second is outside limits AND there is not enough time to relieve the condition. You can never reach the second bullet due to the first bullet that doesn't allow time. Otherwise I like the revised definition.	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The suggested revisions would mean that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. OPAs and RTAs are performed to determine whether these SOLs may potentially be exceeded (through an OPA) or are actually being exceeded (through a RTA). Operating Plans are developed to address "'SOL Exceedances." Do you believe the proposed revisions to the definition of SOL (and companion definition of "SOL Exceedance") allow for a clear distinction between "what the limits are" and "how the system should be operated"

Terry Volkmann - MISO TOP-ISO Task Team - 1,2 - MRO,SPP RE,RF

Answer	No
Document Name	

Comment

We agree Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. However, the removal of the "most limiting" language introduces additional challenges since each component of the definition (Facility Ratings, System voltage limits, and stability limitations) are now individually and simultaneously SOLs for a given facility. The notion that entities continuously assess system performance based on actual operating conditions for each of these components is incorrect as well. While some TOPs have implemented real time voltage stability analysis they are by far the exception. Also, real time transient stability analysis is even more rare. Requiring all TOPs to perform these assessments in real time through the SOL definition will cause undue burden on the industry. While we don't necessarily agree that the current definition needs to be changed we do think it could be simplified by tweaking the proposed language to: "System Operating Limits: The value (such as MW, Mvar, amperes, frequency, or volts) that is the most limiting of the known Facility Ratings, system voltage limits, and stability ratings for a Facility and/or a group of Facilities and system configuration".

In addition we cannot see how the SOL Exceedance definition can be made clear without relating it to "pre- and post- Contingency" concepts.

The SOL Exceedance definition needs to be changed to reflect appropriate control action responses from TOPs/RCs in accordance with our technical rationale provided in answer to the previous question.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	No
Document Name	

Comment

see Q1

Likes 0	
Dislikes 0	

Response

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	

We incorporate our response to Question 1.

Additionally, while we support the SDT's direction of simplifying the SOL definition, the language, "any identified stability limitations" is vague and not measureable. The use of "any identified" does not provide a clear compliance threshold. Also, while this may have already been addressed by the SDT, "Stability" and "Stability Limit" are NERC Glossary Terms and it is unclear if the intent is to incorporate the words as Glossary Terms. Granted, "Stability Limit" does not necessarily define "stability limitations," so there is the potential for confusion.

Suggestion: We offer the following modification to the proposed revisions to SOL.

Reliability limits used for **operating the BES**, to include Facility Ratings, System voltage limits, and limitations **established by the Reliability Coordinator's System Operating Limit methodology.**

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern believes a SOL exceedances should only be applied in real time. Bullet #2 of the proposed definition of SOL Exceedance, suggest that OPA contingency analysis identifying potential SOLs that violate emergency ratings is a SOL Exceedance.

Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. We agree Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. However, the SOL Exceedance definition does not allow for Operator action. An example: a. Excursions above the normal rating, but below the emergency rating should not be SOL Exceedance if flow is reduced to the normal rating in the time frame used to develop the Emergency rating. b. Excursions outside of the normal voltage limits should not be SOL Exceedances if returned within the normal range within a specified time. IROL have a default 30 minutes criteria for operator action. SOL Exceedances should be given similar opportunity for operator action.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
NIPSCO agrees with comments submitted by the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Today, there is a very clear distinction between the performance criteria that we're attempting to observe (e.g. voltage declines at a bus must be less than 10%) and how the system is operated to meet this criteria (e.g. establishing SOLs, directly monitoring criteria and adjusting dispatches if a criteria violation is observed). We're not sure that these proposed definitions add any more clarity – in fact our concern is that these proposed definitions confuse the ideas of "performance criteria" and "system operating limits" (see our comments to 1).	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned the proposed definition of an SOL Exceedance provides more confusion then clarification. Texas RE recommends the following in order to provide clarification:

1. For Actual or pre-Contingency flow on a Facility is above the Normal Rating, the definition should consider post-Contingency above Normal Rating (which could be below Emergency Rating).

2. For Calculated post-Contingency flow on a Facility is above the highest Emergency Rating, Texas RE inquires as to how there can be multiple Emergency Ratings. As written an entity could claim there is a "higher" Emergency Rating and avoid compliance, lower reliability, and submit the System/Facility/Element to a higher risk. Typically, the RC and TOP will define pre-contingency and post-contingency voltage limits. Texas RE recommends using these terms in place of "emergency system voltage limits" in the SOL exceedance definition and updating FAC-011-4 R3 to address these limits.

3. Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs. This would be more helpful if there is a defined time period and a definition for "acceptable level".

4. Actual or pre-Contingency bus voltage is outside normal System voltage limits—System voltage may not be equivalent to bus voltage. This will result in System voltage being set to the extreme edges of what the most extreme bus voltage may be present. System configurations change and elements must remain within element limitations. A 1.07 pu voltage may be reasonable in an industrialized location but not across the Interconnection.

5. For Calculated post-Contingency bus voltage is outside the emergency system voltage limits, a definition of "emergency system voltage limits" would increase clarity.

6. For Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs—This is vague in that it does not describe who sets these limits, how are the limits are communicated, and whether or not there is a methodology.

7. For Operating parameters indicate the next Contingency could result in instability, Texas RE recommends defining "operating parameter". It appears that instability itself may not be considered an SOL exceedence. Was this the SDT's intent?

Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Given the language within the Reliability Standards there still remains confusion between "SOL Exceedance" and violating and SOL or IROL.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	No
Document Name	

Comment

We disagree with SOL and SOL Exceedance definitions. **Refer to comments on question 1 for SOL Exceedances.**

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

NPPD supports the comments submitted by the MISO TOP-IRO Task Team.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

The SOL Exceedance definition ignores the possibility that the system can be operated in real-time operation above the Normal rating of a Facility but within an Emergency rating for less than the time allowed by the Emergency rating and not be an exceedance of the SOL.

Likes 0	
Dislikes 0	
Response	
Robert Roddy - Dairyland Power Cooperative - 1,5	
Answer	No
Document Name	
Comment	
See MISO TOP-IRO Task Team response.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
See the above comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
The proposed definition for bullet item #2 states, "Calculated post-Contingency flow on a Facility is above the highest Emergency Rating". What if there are two (2) levels of Emergency Ratings, say a 30 minute rating and a 15 minute rating? In this case, it would appear there is no SOL Exceedance and thus no operating plan needing developed until the 15 minute rating is exceeded.	
Likes 0	

Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

While we agree that the combination of a revised definition of SOL and a new definition of SOL Exceedance could support a better distinction between "what the limits are" and "how the system should be operated", we do not agree that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs, nor do we agree with the revised definition of SOL and the proposed definition of SOL Exceedance. Please see our comments under Q1, above.

While we agree that the combination of a revised definition of SOL and a new definition of SOL Exceedance could support a better distinction between "what the limits are" and "how the system should be operated", we do not understand what the reliability need is to identify that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. Also, we request the drafting team to provide the rationale for the new definition of SOL and the proposed definition of SOL Exceedance. Please see our comments under Q1, above.

Note: ERCOT and CAISO do not support the above comments.

Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with the comments of the MISO TOP-IRO Task team. Additionally, we don't believe that every facility limit is an SOL nor is reaching a normal rating of a facility is an SOL exceedance. A different term is needed for this.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
We agree Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. However, the removal of the "most limiting" language introduces additional challenges since each component of the definition (Facility Ratings, System voltage limits, and stability limitations) are now individually and simultaneously SOLs for a given facility. The notion that entities continuously assess system performance based on actual operating conditions for each of these components is incorrect as well. While some TOPs have implemented real time voltage stability analysis they are by far the exception. Also, real time transient stability analysis is even more rare. Requiring all TOPs to perform these assessments in real time through the SOL definition will cause undue burden on the industry. While we don't necessarily agree that the current definition needs to be changed we do think it could be simplified by tweaking the proposed language to: "System Operating Limits: The value (such as MW, Mvar, amperes, frequency, or volts) that is the most limiting of the known Facility Ratings, system voltage limits, and stability ratings for a Facility and/or a group of Facilities and system configuration". In addition we cannot see how the SOL Exceedance definition can be made clear without relating it to "pre- and post- Contingency" concepts. The SOL Exceedance definition needs to be changed to reflect appropriate control action responses from TOPs/RCs in accordance with our technical rationale provided in answer to the previous question.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Yes, after much study and reflection. It is a somewhat complicated situation.	
Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	

Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] Yes, after much study and reflection. It is a somewhat complicated situation.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM agrees that Facility Ratings, System voltage limits, and stability limitations comprise the set of SOL. Removing performance criteria from the limit definition helps to clarify the limits.	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See AZPS's answer to Question #1	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

We agree that this approach allows for a clear distinction.

In addition, although we understand IROLs, as a subset of SOLs, are addressed by the SOL Exceedance definition and OPA/RTA concept, it would be helpful to have more guidelines and rationales on the application of the SOL Exceedance definition to address IROL[GM1] .

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

3. Do you agree with removing "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post- Contingency" concepts from the definition of SOL? If no, please explain your concerns.

Robert Roddy - Dairyland Power Cooperative - 1,5	
Answer	No
Document Name	
Comment	
See MISO TOP-IRO Task Team response.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
NPPD supports the comments submitted by the MISO TOP-IRO Task Team.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
We disagree with removal of most limiting criterion. Refer to comments in Q1.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The removal of “most limiting criteria” creates a scenario where multiple SOLs may exist, causing confusion as to which limits the System should be operated to. Also, the removal of “specified system configuration” may prevent stability limits from being identified in real-time, as entities may work under the assumption that stability limits are based on study cases and not real-time System conditions.	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
NIPSCO agrees with comments submitted by the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
No. We believe a fundamental concept of system operations is lost with the removal of most limiting criteria. This defines a safe operating range for operators to meet acceptable BES performance. From a 2007 NERC document, we need to tie the concept of boundary conditions – the specific set of study assumptions and associated outcomes that resulted in acceptable interconnection performance – to the system operating limits within which system operators must operate the system. We also agree that SOL's may be constently changing and that RTAs are very dynamic. However this suggestion puts a boundary on compliance obligations, without limiting what an entity chooses to do on his own system.	
Likes 0	
Dislikes 0	

Response

Terry Volkmann - MISO TOP-ISO Task Team - 1,2 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
We do not agree with removing the terms "pre- and post- Contingency" and "the most limiting criteria" from the definition of SOL, as previously stated.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
We do not agree with removing the terms "pre- and post- Contingency" and "the most limiting criteria" from the definition of SOL, as previously stated.	
Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

Related to our comments in Q1 and Q2, above, we ask the SDT to elaborate why:

a. There is no variability that a Facility rating may or may not be an SOL; and

b. The Emergency Rating is used instead of applicable rating since in some cases, a TOP may apply a rating that is lower than the

Emergency Rating; and

c. There are apparent duplicated conditions for SOL exceedance.

Note: ERCOT and CAISO do not support the above comments.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

We agree with removing the language from the definition of SOL. System Operating Limits are limits no matter if they are the most limiting or not. It makes more sense to move the operating language from the old SOL definition to the SOL Exceedance definition.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment	
While Duke Energy agrees with the removal of the phrases listed in the question, we still have concerns regarding the proposed definition. As written, it appears that the definition of SOL is not a standalone definition in that it does not distinguish between a normal or emergency rating, and needs the definition of SOL Exceedance which includes this distinction, to provide some clarity. The proposed definition of SOL Exceedance includes references to Pre- and post- Contingency, so it could be argued that the phrases the drafting team points to in the question have not been completely removed, as they are still present in the SOL Exceedance definition. We reiterate that a specific reference to both Normal and Emergency Ratings could aid in clearing up the ambiguity that presently exists in the definition of SOL.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
A limit, including SOL, is a parameter. Removal of the identified terms eliminates performance criteria from the SOL definition. Married with the proposed new definition for SOL Exceedance, this change to SOL makes the definition much cleaner with SOL being a set of parameters, each of which must be addressed within RTA/OPA.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	

Comment

We agree providing that our comments above are duly addressed.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

1. SOL Exceedance need to have a time frame to allow operator action. SOL Exceedances, by themselves, may not considered non-compliance issues. However, not allowing operator action to avoid declaring an SOL Exceedance will create an unnecessary burden of evidence capture for condition that the System Operator have under control.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	Yes
Document Name	

Comment

the most limiting criteria: The phrase, even with the parenthetical examples, was subject to unlimited interpretations.

specified system configuration: The new and future enforceable Standards focus on Facilities and their impact to the System. The term does not add clarity in light of the new and future enforceable Standards.

operation within acceptable reliability criteria: The word, “Acceptable,” is vague and not measurable. “Reliability criteria” is undefined, vague and can only be inferred.

pre- and post- Contingency: Contingency awareness is addressed in TOP-002-4.

Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree that the TOP should determine the appropriate Facility Ratings for use in operations, in accordance with the requirements set in the RC SOL Methodology? Note: This assumes the Facility owner will continue to provide the Facility Ratings to the RC and TOP as currently required under FAC-008. The RC Methodology will simply describe the manner in which the TOP determines which of those owner-provided Facility Ratings are appropriate for use in operations.

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	No
Document Name	

Comment

if the SDT wants to standardize existing methodologies, this is not the place to do it as FAC-008 addresses facility ratings.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

The TOP should be developing their own Facility Rating methodology. As the individuals most familiar with their system.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy does not agree with the proposed direction of having the TOP to determine the appropriate Facility Ratings for use in operations. We believe that the TO/GO should be determining the rating, as they already have their own ratings methodology (FAC-008). We disagree with the premise that the RC may overtake the TO's ratings methodology. We suggest the drafting team consider bypassing the requirement of an RC creating an SOL Methodology, and require that the TOP create its own SOL Methodology under FAC-014. Dependence on the actions/intervention of the RC may vary by region, and we suggest that if a particular region relies more heavily enough on the RC to require an RC SOL Methodology, perhaps a specific regional standard should be created for that region.

An overarching clarification we would like made, is in regards to the apparent shift towards considering the actual Facility Rating as the SOL. If this is the drafting team's intent, we ask how the outlining of a specific SOL Methodology affects the determination of a Facility Rating being the SOL. Will the SOL Methodology be used to re-visit the Facility Rating and its appropriateness as the SOL? More clarification as to how these two approaches will interact would be appreciated.

Lastly, based on our review, it appears that some aspects of the proposed would require entities to operate in a more limiting fashion, and in some cases intruding upon current TPL standards. For example, the proposed definition of SOL Exceedance has appeared to eliminate the possibility of an entity using its Emergency Ratings pre-Contingency. This conflicts with current TPL standards. For single contingency under the TPL standards, the requirement is that you do not have consequential or inconsequential load loss. There is nothing there about not being able to use your long term Emergency rating on a pre-contingency basis.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

The intent of the requirement as outlined in the explanation/rationale and the question is not clear from the requirement. The requirement should be clear that the RC SOL Methodology must utilize Facility Ratings that are provided by the TO and operate within those Facility Ratings. As written, it may be implied that the RC SOL Methodology may require the TOP to develop ratings that are different or use different methodologies than the TO's Facility Ratings. Recommend R2 be rewritten as: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings **provided by the Transmission Owner** to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area."

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Facility owners should decide what kind of risk they are willing to take in operating their facilities. These assumptions are rolled in to the facility rating methodology. It is not appropriate to take this away from the facility owners.

Some RCs serve a very large geographic area with varying environmental conditions (i.e. Northern Canada vs. Southern US). These RC will have a difficult time developing uniform criteria valid for the entire region.

Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does agree that the TOP should determine the appropriate Facility Ratings; however, the last sentence in the requirement is confusing. Because the RC does not derive the facility ratings, the use of the word "common" is confusing. AZPS respectfully requests that the sentence be clarified.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	

Concern: The Requirement states the "…Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations." The language is broadly written to, likely, provide flexibility to the RC in creating its Methodology. However, the potential unintended effect with the RC unilaterally determining the Methodology is it may not address the materiality of Facilities, possibly requiring assessment of each Facility on the TOP's system and creating an onerous task for TOPs executing the Methodology—all with little benefit to reliability.

For example: In R3, the TOP is required to provide a "System Voltage Limit." For the purpose of this example, an unbound Methodology, one without a single high and low limit that is appropriate for the TOP's System, could require calculation of System Voltage Limits for every Facility on the TOP's System.

Also, while collaboration between the RC and TOP can be inferred, the proposed revised Standard is without explicit guidance or recourse should the TOP have concerns about the scope of the RC's Methodology.

Suggestion: Add language to provide that the RC create its Methodology in consultation and collaboration with the TOPs. Also, that the RC and TOPs come to a consensus regarding the scope of the Methodology. We recognize, for purposes of compliance determinations, it is difficult to provide evidence supporting "consultation and collaboration" so focused the suggested Requirement language on consensus. We offer the following

Requirement and Measure language as a framework for further consideration.

FAC-011-4

R1.1

Each Reliability Coordinator shall come to a consensus through consultation and collaboration with the Transmission Operators regarding the following points of its SOL Methodology:

R1.1.1

The method Transmission Operators use to determine the applicable Facility Ratings to be used in operations and the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R1.1.2

The method Transmission Operators use to determine the applicable steady-state System voltage limits to be used in operations.

R1.2

Each Reliability Coordinator shall come to a consensus through consultation and collaboration with the Transmission Planners regarding the following points of its SOL Methodology:

R1.2.1

The study models and the level of detail the Reliability Coordinator requires determining the stability limitations to be used in operations.

R1.2.2

How stability limitations are established when there is an impact to more than one Transmission Operator in the Reliability Coordinator Area.

Measures for R1

The Reliability Coordinator shall have evidence the Transmission Operators and Transmission Planners accepted the points of the SOL Methodology as listed in R1.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

1. We agree that the TOP should make the determination, but ask the SDT to take into consideration that TOPs have existing documented processes and methodologies that would no longer apply when determining Facility Ratings for use in operations. This requirement imposes a process onto TOPs that may drastically deviate from existing practices, therefore we suggest an addition to this requirement that the RC gather and review

existing methodologies from each TOP in their reliability area and come to a mutually agreed upon methodology with the affected TOPs.

2. Also the standard should require the RC to obtain TOP agreement anytime the SOL Definition inserts the usage of "sufficient time" into the determination of an SOL Exceedance.

3. Additionally, will the RC set requirements for the TOP determine equipment ratings for set ambient temperature ranges and establishing emergency ratings on set time lengths, such as 30 minutes – or 2 hours?

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

NIPSCO is concerned that the requirement does not provide adequate assurance that the RC will respect the ratings established by the TO or the TO's FAC-008 methodology. As written, the language is vague and could be interpreted as allowing an RC to determine the ratings that a TOP must use (including normal and emergency ratings and seasonal changeover dates) without respecting the TO's authority to establish such Facility Ratings.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	Yes
Document Name	

Comment

Given FAC-014-3/R2 requires the TOP to establish SOLs, there can (and often does) exist a time lapse between a TO establishing a Facility Rating and the TOP using that Facility Rating to establish/implement the SOL. Similarly, sometimes the "schedule (per FAC-008-3/R6)" is different between RCs and TOPs, leading to different entities having different Facility Ratings information depending upon when they were informed by the TO. Suggested comment is: recommend modifying the applicability of FAC-014-3 to include Transmission Owners. Likewise, recommend adding a requirement that, when a Transmission Owner changes a Facility Rating prior to a scheduled request, the Transmission Owner shall provide the updated Facility Rating to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s).

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE recommends this requirement include additional details that the SOL determined by the TOP should not exceed the Facility Rating. Part 3.1 of proposed FAC-011-4 includes a requirement that “System voltage limits are not outside of the Facility voltage ratings”, but there is no requirement that SOLs should not exceed the thermal limit component of a Facility Rating.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM agrees that the TOP is the appropriate reliability entity for Facility Rating usage in the agreed upon manner established by their RC.	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
By definition, Facility Ratings are one factor in determining SOLs so all Facility Ratings need to be incorporated into the determination of SOLs. The requirement should be modified to "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to incorporate the Facility Ratings in establishing SOLs. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area."	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
The word "determine" in the requirement can be confusing. The requirement could be interpreted that the Transmission Operator calculates the facility ratings. The following language may be more clear, "Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine **which of the owner-provided** Facility Ratings **should** be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area."	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes. It's not fully clear whether this will eliminate the risks outlined above, since it seems there is still potential that the Facility Ratings provided by the TO may not provide what is required, but it will depend on what the actual RC methodology says.	
Likes 0	

Dislikes 0	

Response

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: ERCOT does not support the above comment.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes the TOP should follow a consistent methodology, and continue to provide the RC its application Facility Ratings used in Operations. BPA believes this benefits all TOPs.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

We agree with R2, although we are concerned that the non-uniformity of the Facility Ratings provided by the TO can add burden to the application of the method to all scenarios. Also, guidelines regarding an appropriate method would be helpful in the final version of the standard.

To “address" the use of common FR does not require the common FR be used.

Suggestion: “The method shall **require** the use of common Facility Ratings between the RC and the TOPs in its RC area.”

The language can also be simplified slightly –

Suggestion: "The method shall require the **same** Facility Ratings by used by the RC and the TOPs in its RC area."

Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - MISO TOP-ISO Task Team - 1,2 - MRO,SPP RE,RF	
Answer	
Document Name	
Comment	
The MISO TOP-IRO TT is only responding to Questions 1, 2 and 3	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree that the TOP should establish the System voltage limits pursuant to the RC SOL Methodology, and that the proposed Requirement R3 provides sufficient clarity for what the RC SOL Methodology must include?

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS respectfully suggests that Requirement 3.3 is troublesome because the minimum operating system voltage under multiple contingencies could be below the highest UVLS settings where the UVLS is used as a safety net. Because it is acceptable for UVLS to act and stabilize the system voltage to a more acceptable level, the "lowest allowable System voltage" could differ depending upon the system topology and characteristics in effect. Stated another way, while the intent of requirement 3.3 is reasonable for the all lines in service condition, it may not be for an N-1 or N-2 conditions.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
See our comments to question 4 above. Duke Energy has no issue with the TOP establishing the System voltage limits or even the criteria proposed, however, we do not see justification to impose the RC's SOL Methodology onto the TOP.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
The Transmission Operator and Transmission Owner should establish voltage limits because of Facility considerations. Regarding Part 3.5, common voltage limits may not be appropriate between the Reliability Coordinator and Transmission Operators in its footprint. Voltage limits should be identified uniquely between a RC and each of its TOPs.	

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	No
Document Name	

Comment

PJM agrees that the TOP is the appropriate reliability entity for this determination and with the predominant sentiment of the requirement.

- However, the proposed R3 does NOT provide sufficient clarity in its present draft construct. Nor does it remain true to the intended objected stated within the SOL Definition Explanation of Proposed Revision section [above] to respect advancements in technology. R3.1 & R3.2 require that "System voltage limits are not outside" of the Facility voltage ratings or NPIR requirements. Technology advancements permit the setting of discrete limitations, including facility voltage limitations, on any bus on a given system. For facilities where no discrete facility voltage limitation is applied, the system can implicitly apply the System voltage limit on a voltage class or per unit level, which may be outside the limits for any given discrete facility ratings. Each can be analyzed, monitored and controlled reliably within OPA/RTA, without the requirement that the System voltage limit not be outside of the Facility voltage ratings and/or NPIR requirements.
- Suggested language change options:
    - (3.1) Require that Facility voltage ratings are respected by and coordinated with System voltage limits;
    - (3.2) Require that Nuclear Plant Interface Requirements are respected by and coordinated with System voltage limit

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE recommends the RC SOL methodology address pre-contingency and post-contingency voltage limits, with the SOL exceedance definition updated to match this terminology.

Texas RE noticed FAC-011-3 R1 is not fully mapped to FAC-011-4 Part 3.1, as Part 3.1 does not address thermal limits.

Likes 0	

Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] We believe an additional bullet (3.7) should be added that says "Address coordination of System voltage limits between adjacent Reliability Coordinator Areas." There should be some coordination so that along RC Area seams there do not continue to be issues where differing voltage limit criteria results in real-time issues.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Yes it provides clarity but Requirement 3.5 should be handled via a revision of FAC-008.	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
As mentioned in the response to question 1 above, while this document states that FAC-008-3 should include facility voltage ratings, that is not something that we have seen TOs do in practice. If the intention is that they are required, then it needs to be clarified and communicated somehow. If these facility voltage rating exist, why can they not be used directly instead of requiring the TOP to develop separate system voltage limits? Lack of voltage monitoring? Are there voltage considerations that the TOP would have that wouldn't be covered under a rating (and wouldn't be covered under voltage stability limits)?	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Requirement text should be modified to "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to incorporate the steady-state System voltage limits in operations establishing SOLs. We agree that TOP should establish the system voltage limits pursuant to RC SOL methodology however there seems to be redundancy between this requirement and existing VAR-001-4 R1. The intent of VAR-001-4 R1 is for TOP to system establish voltage schedules which may use low and high limits in accordance with SOLs. If FAC-011-4 R3 will require establishment of system voltage limits then the VAR-001-4 R1 should be removed as it creates duplicate requirement. R3.2 should be modified to state 'Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements for buses/equipment identified in NPOA'.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
In regards to System Voltage.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We believe an additional bullet (3.7) should be added that says “Address coordination of System voltage limits between adjacent Reliability Coordinator Areas.” There should be some coordination so that along RC Area seams there do not continue to be issues where differing voltage limit criteria results in real-time issues.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
NIPSCO is concerned that the requirement does not provide adequate assurance that the RC will respect the Facility voltage ratings established by the TO or the TO’s FAC-008 methodology. As written, the language is vague and appears to allow the RC to determine the voltage ratings that a TOP must use.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Comment	
1. We agree that the TOP should make the determination, but ask the SDT to take into consideration that TOPs have existing documented processes and methodologies specific to their needs that would no longer apply when establishing System voltage limits for use in operations. This requirement imposes a process onto TOPs that may drastically deviate from existing practices, therefore we suggest an addition to this requirement that the RC gather and review existing methodologies from each TOP in their reliability area and come to a mutually agreed upon methodology with the affected TOPs. 2. To avoid issues where differing voltage limit criteria result in Real-time issues, we believe an additional bullet (3.7) should be added that says "Address coordination of System voltage limits between adjacent Reliability Coordinator Areas" to allow for coordination along RC Area seams.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
We incorporate our response to Question 4.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

We agree with the intent of R3, but the sub-bullets are a burden to compliance with no benefit to reliability. They tell the “how” more than the “what” and should be part of the guidelines to the requirements. Why is R3 so detailed regarding the content of the method compared to R2? More uniformity of structure between R2, R3 and R4 would be beneficial. More precisely, we think that 3.4 is redundant with the body of the requirement and not needed, and 3.3 addresses the allowed use of UVLS in SOL determination that should be a separate requirement (combined with allowed use of RAS in R4). Alternately, if 3.3 is maintained, it should take into consideration voltage triggered RAS.

3.5 should be reworded in line with our suggestion for R2. Require the “same” System voltage limits be used by the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator instead of "common".

Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	

With regard to proposed requirement R3.1, equipment/facility voltage ratings come from Transmission Owner and Generation Owner. While the establishment of equipment/facility voltage ratings may be implied through the NERC definition of Facility Ratings, there is no direct requirement in FAC-008-3 for TOs and GOs to determine equipment/facility voltage ratings. There may be value in having a corresponding requirement added to FAC-008-3 requiring TOs and GOs to determine equipment/facility voltage ratings and to communicate those upon request. This would close the loop, allowing TOPs to have access to the equipment/Facility voltage ratings they need in order to establish system voltage limits. The SDT might also consider adding “equipment voltage ratings” to proposed requirement R3.1.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

6. Is it clear what System voltage limits are? Does a definition for “System Voltage Limits” need to be created? A draft definition under consideration by the SDT is “System Voltage Limits: The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations.” Please provide your perspective on whether, currently, it is clear what is meant by System voltage limits, and if not, what you believe to be the appropriate definition.

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	No
Document Name	

Comment

Yes it is clear; however, we do not feel a definition of System Voltage Limits should be created.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. It is not clear if a TOP would be required to provide a “System Voltage Limit” for EACH Facility on its system, or if a single high and low limit that is appropriate for its system should be provided.

2. The System Voltage Level in the definition should refer to steady state condition to avoid nuisance SOL Exceedances. In addition SOL Exceedance definition should have a time frame to allow System Operator action to return voltage within the normal range, such as reactive device switching, generator voltage schedules. IROL Exceedance has a time frame to allow System operator action, so should SOL Exceedances.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

It is not clear if a TOP would be required to provide a “System Voltage Limit” for EACH Facility on its system, or if a single high and low limit that is

appropriate for its system should be provided.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
It is not clear what system voltage limits are without a definition. Using another term in place of system voltage limit like "allowable voltage range" may help clarify.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Please develop language clarifying System Voltage from a Single Bus Voltage.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It is not clear if a TOP would be required to provide a "System Voltage Limit" for EACH Facility on its system, or if a single high and low limit that is appropriate for its system should be provided.	

Likes 0	
Dislikes 0	

Response

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	No
Document Name	

Comment

The System Voltage Level in the definition should refer to steady state condition to avoid nuisance SOL Exceedances. In addition SOL Exceedance definition should have a time frame to allow System Operator action to return voltage within the normal range, such as reactive device switching, generator voltage schedules. IROL Exceedance has a time frame to allow System operator action, so should SOL Exceedances.

It is not clear what System voltage limits are. For example, system voltage schedules are required per VAR-001-4 R1. Is a system voltage schedule a System voltage limit? System Voltage Limit should be defined and the term system voltage schedule should no longer be used to avoid redundancy as having both creates confusion.

The proposed draft definition of system voltage limits should not use terms maximum and minimum and normal and emergency. The definition should define these as System Operating Limits that that provide for reliable system operations. Using the terms maximum/minimum and normal/emergency may make it prescriptive as TOP can determine these limits based on SOL methodology specified by RC and voltage ratings determined by TO.

- *Actual or pre-Contingency bus voltage is outside normal System voltage limits;*

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

Although a System Voltage Limits definition is needed, the proposed definition, as found in the question, ignores that the acceptable voltage levels can vary according to the duration of the voltage excursion. The drafting team would review the recently released NERC draft Reliability Guidelines for Reactive Power Planning and Operations and its explanation of the need to permit something other than static voltage limits from the planning horizon into the operating horizon (i.e. note pages 24-25 of the document found here http://www.nerc.com/comm/PC/Documents/Reliability%20Guideline%20-%20Reactive%20Power%20Planning%20and%20Operations.pdf).

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
It would be helpful to define the "System Voltage Limits" so that it is clear that the system voltage limit is not one value, but could be different values at each bus.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
A definition for System Voltage Limits would be beneficial. There seems to be some confusion if system voltage limits are system-wide voltage limits or if each facility can have different voltage limits similar to System Operating Limits. Also FAC-008 does not seem to mention voltage limits. Where is the requirement for the facility owners to provide facility voltage ratings to be used in the calculation of System Voltage Limits?	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
It would be helpful to have a definition for System Voltage Limits. In addition to the definition considered above, it may be useful to add that the system voltage limits, "and is within applicable facility voltage ratings".	
Likes 0	
Dislikes 0	

Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
I would like to suggest that System Operating Limits are determined by factility voltage ratings that are processed through the OPA/RTA.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
We support a new System Voltage Limits definition. Definitions clarify compliance determinations and entities' implementation of Standards.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
NIPSCO does note that like ATC believes that the definition of system voltage limits does need to allow for differing time components that may be associated with short term or dynamic ratings.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
System voltage limits does not require a definition in the NERC glossary. Most users, owners, and operators of the BPS are familiar with the term and the proposed definition is not necessary.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy believes that it is clear what System voltage limits are. However, if the SDT chooses to pursue an industry wide definition, we would support the definition proposed in question 6.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	

New definition for “System Voltage Limits” is not required.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	

It is clear what System voltage limits are - and to the extent it is not, this clarity must be covered within the RC's SOL Methodology. There is no need to create a NERC Glossary definition for this.

Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee

Answer	Yes
Document Name	
Comment	

We interpret System voltage limits to mean voltages on the system or specific buses. We do not believe a definition is needed. However, if one is needed, then the one proposed above seems reasonable. Still, that definition does not imply that System voltage limits are SOLs.

Note that the proposed definition of System voltage limits more or less concurs with our comment under Q1 that System voltage limits may not be the SOL. There are a number of places in the Eastern Interconnection that have SOL defined as the total MW flow on an interface (e.g. in IESO, NYISO, APS, etc.) that are restricted by the post-contingency voltage levels in the area (on buses) near or within the defined interfaces.

We suggest the SDT consider distinguishing between a voltage limit and a voltage rating. Where the rating is set to protect equipment

damage or the ability for equipment to operate and the voltage limit is a value to operate to, to protect the voltage ratings.

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Yes, BPA has a clear understanding of System voltage limits. BPA supports the SDT's draft definition of "System Voltage Limits", as it would be valuable to the industry.

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	Yes
Document Name	

Comment

Peak supports the proposed definition and believes it is a good idea to create a definition for system voltage limits. Doing so will bring more clarity.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	

Comment

We think that the proposed definition is useful and a useful addition to the SOL related standards. Again, guidelines on the determination of those limits with regards to the applicable requirements would be helpful.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not agree with the proposed definition of "System Voltage Limits", as the term emergency voltage limits is not clear. Texas RE recommends modifying the definition and using the terms pre-contingency and post-contingency in place of Normal and Emergency.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	

Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

7. Do you agree that the proposed use of the word stability "limitations" is a better choice than "limit" to capture the full breadth of all phenomena and determination methods/time frames for stability concerns?

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees that the use of the term "limitations" is a better choice than "limit". The term "limit" is already widely used and accepted throughout the industry. Replacing it with a term unfamiliar to the industry without clearly stated justification, would be confusing to some in the industry.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Limitation is defined as "the act of limiting or the state of being limited, a restriction". A limit is a "boundary, something that confines or restricts". Requirement R4 addresses Contingencies which are better described by "limit".	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
As noted in Q1 there seems to be confusion between the words "limitation" and "criterion" which is evident in 4.2. There needs to be clarity.	
Likes 0	
Dislikes 0	

Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
As previously noted, “Stability” and “Stability Limit” are NERC Glossary Terms and it is unclear if the intent is to incorporate the words as Glossary Terms. Also, “Stability Limit” does not necessarily define “stability limitations,” so there is the potential for confusion. Additionally, we agree that “limit” does not capture the system’s phenomena.. **Suggestion**: Use “limits,” the plural form to capture the system’s phenomena.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
As stated in comments for requirements above the text of this requirement should be changed to “Each Reliability Coordinator shall include in its SOL Methodology the method for incorporating stability limitations in establishing SOLs.	
Likes 0	

Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. This requirement does not state that the TOP would determine the minimum stability limitations, based on the RC's methodology. This needs to be revised to similar wording in Requirement R2 and R3. 2. We agree that the TOP should make the determination, but ask the SDT to take into consideration that TOPs have existing documented processes and methodologies specific to their needs that would no longer apply when establishing stability limitations for use in operations. This requirement imposes a process onto TOPs that may drastically deviate from existing practices, therefore, we suggest an addition to this requirement that the RC gather and review existing methodologies from each TOP in their reliability area and come to a mutually agreed upon methodology with the affected TOPs.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
The SDT might consider using "Stability Limits" in the revised SOL definition and then revising the definition of Stability Limits in the NERC glossary so	

that it goes well with this definition of SOL. The stability limitations language in the current definition can work but it may lead to some confusion.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

8. With regard to proposed Part 4.1: Do you agree that the RC SOL Methodology should have criteria that consider *all* items in Parts 4.1.1 – 4.1.4? Are there additional criteria that should be included? If yes, please list and explain. Are there criteria that are included, that you believe should *not* be included?

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Yes, all of the criteria should be included. No, additional items are needed.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
On a case by Case basis: In the Operations Horizon and specifically OPA/RTA time frames, angular, frequency deviation (not listed), and system damping thresholds should not be considered.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] There are too many questions here to answer. We wish to answer Yes that all items in 4.1.1 – 4.1.4 should be included and also wish to say No there are no additional criteria that should be included.	
Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Transient studies should be performed "offline"	
Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
This requirement is too long, and too prescriptive to be in the standard. We recommend removing the criteria from the requirement. We suggest stating the requirement, and then state directly that a TOP must determine an SOL consistent with the requirement. It is unproductive to be this prescriptive in a requirement, and require an RC to have an SOL Methodology. An RC would be able to just copy what is in the requirement, and place in its methodology. There is no need for a methodology when the requirement is this prescriptive. We do not disagree with the content of the criteria, just that it is placed in the requirement.	
Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
The SOL Methodology for determining the stability limitations to be used in operations shall be primarily based on 0ff-line studies with an exception of limited number of facilities that are of critical importance for reliability of BES where on-line stability tools have to be used. This has to be clearly stated due to limited availability of high quality on-line stability tools and applications and their challenging robustness and accuracy.	
Likes 0	

Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
No other criteria are needed.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agree, and do not believe there should be any additional criteria included.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
No additional criteria are neccesary. No criteria are included that should not be.	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Each RC area should have a criterion for each stability item identified in Parts 4.1.1-4.1.4. However for any particular TOP or RC area of the BES a particular criterion may at the present time have little bearing on determining SOLs. Over time, this may change and therefore the need for a review and criteria is important. However, coordination should be considered with the requirements of TPL-001-4. Having significantly different criteria between the RC and the PC's within an RC's area could become problematic if issues are "missed" in the planning assessments due to the differences in criteria.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Yes, it should include all of the defined criteria.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Yes, the RC methodology should have criteria that consider all the items. There are no additional criteria that should be included. There are no criteria listed that should be excluded.	
Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Stability criteria in Parts 4.1.1 - 4.1.4 are adequate - no additions or deletions recommended.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
What is the difference between a voltage limit and a steady state voltage stability limit?	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports the proposed revisions and believes specifying a regional performance criteria is a great addition.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We agree with the proposed criteria, but would all RCs be automatically obligated to define criteria for all the 4.1 sub-bullets? What if angular stability is not relevant in a particular RC area? TPL-001-4 R6 should be revised to include all these elements.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	

Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
Yes, for the first question and no for the second and third questions.	
Likes 0	
Dislikes 0	
Response	

9. With regard to proposed Part 4.2: Do you agree that the RC SOL Methodology should consider the contingencies listed in Parts 4.2.1 and 4.2.2? Are there additional Contingencies that should be included? If yes, please list and explain. Are there Contingencies that are included, but you believe should *not* be included?

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

Requirement 4.2.1 contains the phrase "or without a fault." Because the "with" fault condition is more severe, if performance is acceptable with the fault condition, it would be acceptable without the fault also. For this reason, AZPS recommends that this phrase be removed. If the SDT disagrees, AZPS requests that it provide an explanation or example of why the no fault case is needed. It should also be made clear that stability studies are not expected in real time (using RTCA for example).

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

See our comment to question 8 above. We do not disagree with the content of the criteria, just that it is placed in the requirement in this manner.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No
Document Name	

Comment

Sub-Part 4.2.1 should read "…by single phase Fault to ground, or three phase Fault with normal clearing…".

To include all Elements that could affect stability, suggest revising sub-Part 4.2.1 to read in its entirety: 4.2.1 With normal clearing, with or without a Fault, the loss of any System Element. This encompasses all faults.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] There are too many questions here to answer. We wish to answer Yes that all items in 4.2.1 – 4.1.2 should be included and also wish to say No there are no additional criteria that should be included.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Yes, all of the criteria should be included. No, additional items are needed.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Yes on Part 4.2.1. No on Part 4.2.2.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
Does R4.2 mean that every possible event that meets the criteria be simulated to find limitations? Or is the intent to allow the RC and/or TOP to select the events most likely to be cause a severe event and test those? The requirement should be written to clarify that either way since the current writing would allow for either interpretation.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Contingencies listed in Parts 4.2.1 and 4.2.2 are adequate - no additions or deletions recommended.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

The standard should explain what it means by “or” for single phase versus three phase faults. This is important because the system is often operated beyond how the system is evaluated in the planning horizon. Specifically, the TPL standards only require the system to be studied for single line to ground faults with a failure of a protection system. However, when a protection system is removed from service in the operating horizon, which is required to perform maintenance, any operating horizon requirement to examine three phase faults puts the TOP in a condition beyond what the TP has designed the system for. By using “or” between single phase and three phase, or by adding words like, “whichever is more severe”, the TOP will likely be forced to study a three phase fault for this short duration operating scenario, regardless of the very low probability of a three phase fault occurring while the protection system is out of service for maintenance. Suggested wording: “Loss of one of the following by three phase Fault for Normal Clearing scenarios, single phase Fault for delayed clearing scenarios, or without a Fault.”

Additionally, The single block DC should also clarify it means a single faulted pole as three phase fault for a DC circuit is undefined and could be ambiguous.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	

Yes, it should include all of the defined contingencies.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	

Concerned with the premise identified in R5 that the RC may identify a methodology beyond that studied and documented by the Transmission Planner as required in TPL-001-4. Both the RC and the Transmission Planners should have a mutual understanding of the stability issues of the system and how these could impact an SOL. This should be discovered through the review of a planning assessments required to be performed in TPL-001-4, not an SOL methodology.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

We suggest removing "loss of any" as the terms "loss" and "contingency" are redundant.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

No additional contingencies are neccesary. No contingencies are included that should not be.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

We agree, and do not believe any additional contingencies should be included.

Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We agree with the listed contingencies as the minimum to be considered for SOL evaluation, but it is not clear why they are listed in R4 and applicable only to stability related SOLs. What about Facility Ratings and System Voltage limits? What contingencies need to be used for "Calculated post-Contingency flow on a Facility is above the highest Emergency Rating"? In TPL-001-4, "Applicable Facility Ratings shall not be exceeded" for the contingencies listed in the tables: the same approach should apply here. We suggest removing the contingencies from R4 and providing a table, perhaps as an attachment that would be used for defining the single Contingencies relevant for this standard. 4.2.2 needs to be reworded : "Multiple Contingencies identified in Requirement R5." Delete "loss of any".	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports the criteria.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
Yes for the first question and no for the second and third questions.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	
Document Name	
Comment	
Contingencies identified are adequate.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	

Likes 0	
Dislikes 0	
Response	

10. With regard to proposed Part 4.3: When instability risks are identified, there are various studies or assessments that analyze different transfer levels, load levels and generation dispatch combinations. The intent of Part 4.3 is to ensure that the RC SOL Methodology adequately describes how these various factors are considered in the identification of instability risks. In the identification of stability risks, the RC SOL Methodology should consider the levels of transfers, load and generation dispatch. Should the RC SOL Methodology include a description of any additional types of information?

a. Should proposed Part 4.3 specifically include "offline analyses"?

b. Should proposed Part 4.3 include forced Transmission and generation outages (*i.e.*, N-1-1)?

c. Should proposed Part 4.3 include planned outages (*i.e.*, all planned outages in the base case)?

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	No
Document Name	

Comment

a-yes

b-no

c-yes

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

A. Yes. NIPSCO believes "offline analyses" should be included.

B-C. NIPSCO believes that specifying N-1-1 or planned outages reduces the flexibility that the SDT is trying to preserve for the RC.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	
Yes there should be more discussion of any intended requirements regarding “online vs offline” stability analysis.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We believe Part 4.3 as presented is sufficient. There is no need to indicate “offline analyses” since whether the SOL is determined through on-line or off-line studies is irrelevant. Further, whether or not SOLs need to be developed for outage conditions or their development considers planned or forced outages is a matter of what SOLs are needed for the anticipated or encountered conditions, not a part of methodology to be documented.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
4.3 is Administrative in nature and open to Auditor interpretation and as such needs to be rewritten. Moving forward it would be expected that Stability studies should be assessed in the Outage Coordination (IRO-017) time frame – for those entities without Real Time Stability Tools - and per engineering judgement Parts a, b, and c can be addressed in that venue and do not need to be stated explicitly here.	
Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] 4 questions here....Yes there should be more discussion of any intended requirements regarding “online vs offline” stability analysis.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
The type of stability studies, online verses offline, should be left to the individual TOP or TP. As for Parts b and c, these are studied as part of TOP-002. This work would include voltage schedule, unit output, and other adjustments as typically considered when performing stability analysis. If anything, a reference only to the already required studies might be appropriate.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Part 4.3 is not required. The information being asked for can be gleaned from the preceding Parts. “How” should not be in a requirement.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy does not believe that these items should be included in an SOL Methodology. Perhaps planned outages may be appropriate, but disagree with the addition of "offline analyses" and N-1-1.

Also, as written, it is not clear how section 4.4 in the proposed FAC-011 will adequately synch up with what is required in FAC-014. Each RC or TOP must consider what limitations a Planning Coordinator provides in its planning assessments, but it is not clear on what information is supposed to be conveyed, and how it should be applied.

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

The standard should avoid being overly prescriptive. The RC should determine for itself what forced outages should be included. The RC should determine for itself what planned outages should be included.

Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Proposed 4.3 is sufficient

Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
To retain its flexibility the RC Methodology should not require any additional items.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
The descriptions of additional types of information in a, b, and c are not needed. 4.1 already requires stability performance criteria for single contingency and multiple contingencies. The additional language in a, b, and c, may limit TOP and RC flexibility in developing their processes for identifying instability risks.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
We believe Part 4.3 as presented is sufficient. There is no need to indicate "offline analyses" or "forced or planed outages" since whether the SOL is determined on or off-line is irrelevant for. Further, whether or not SOLs need to be developed for outage conditions or their development considers planned or forced outages is a matter of what SOLs are needed for the anticipated or encountered conditions, not a	

part of methodology to be documented.

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	No
Document Name	

Comment

I also comment some in question 11.

I suggest being a little more detailed in what the RC should provide.. IE

-If simulating a specific time then outages planned for that time

- If simulating a generic time (Summer Peak) then room for the RC to specify that certain N-1-1 or G-1+N-1 combinations are run, but not require a brute force running of all N-1-1. Alternatively, criteria that the RC sets and then the TOP determines what N-1-1 to test. For example, the RC could require that the TOP select their most limiting events and run them in N-1-1 configuration with each other.

4.3 should specify that it requires offline studies but does not precluding the use of real time simulation.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes bullet ’a’ is not needed as long as there is flexibility between on and offline analyses. Bullet ’b’ should be included. However, there needs to be more description of what a forced outage is. Bullet ’c’ should be included.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
We think that “the levels of transfers, load and generation dispatch” is general to SOLs and should be applicable outside of R4, not only for stability limitations (e.g. offline load flow study that is used to identify System Voltage limits violations). The planned or forced outages to consider in the studies should be defined by the RC Methodology according to “expected” or “credible” operating conditions.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
We agree that the Part 4.3 should specifically include the term “offline analyses”. We do not agree that the Part 4.3 should include N-1-1 outages, as that may contradict the underlying strength of the transmission infrastructure during the planning phase and consequently may flag issues in operations that may not be solvable. We do agree with including known planned outages in the base case for studies being performed well in advance and for sensitivity studies. However, we do not agree to (possibly unintended) expectation that stability studies have to be re-run for each planned outage.	

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. Regarding item 'a.' – Yes, there should be more discussion of any intended requirements regarding "online vs offline" stability analysis. 2. Regarding item 'b.' – No, forced Transmission and generation outage information isn't necessary. 3. Regarding item 'c.' – Yes, planned outage information should be included.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
If the RC and TOPs are dependent on an OPA and RTA to identify stability limitations, Texas RE recommends all outages be considered in these assessments. If the SOL definition is modified to remove the "specified system configuration", it is important that the Standard specifies that stability limits and IROLs be determined with all known outages applied.	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	

We support using the qualifier "realistic" in Part 4.3.

Specifying "off-line analyses" is not necessary since, as currently worded, Part 4.3 seems to allow use of both on-line and/or off-line analyses.

All credible contingencies to consider must be addressed in R5 - do not muddy the water by specifying contingencies in Part 4.3. Wouldn't all planned outages already be included in the day-ahead or hour-ahead operations base case? We do not see the need for planned outages to be specifically mentioned in Part 4.3.

Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	

We would like to change our vote to NO at this time but edit mode does not allow me to since I already submitted once.

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	
Document Name	
Comment	
Something to consider for FAC-011-3 R4 is for the RC to identify the criteria that will qualify a stability limitation to be considered an IROL. In other words, RC should specify a clear criteria as to when a stability limitation becomes an IROL. Regarding N-1-1 forced outage operations, it might be a good idea for there to be a requirement in FAC-011 for the RC's SOL Methodology to specifically address SOL/IROL establishment for N-1-1 scenarios, where the first N-1 is either a planned outage or a forced outage. No need for offline analysis to be addressed in FAC-011.	
Likes 0	
Dislikes 0	
Response	

11. With regard to proposed Part 4.3: The SDT used the term “realistic” as opposed to “expected” in order to perform sufficient assessment to identify potential stability risks. The SDT takes that position that “unrealistic” stressing scenarios may be more of an academic exercise to “break the system” and may not translate to actual operations preparedness. Is “realistic” transfer, Load and generation dispatch levels an adequate description or should more clarifying language be added, such as a reference to firm and non-firm transfers?

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
We disagree with the use of the term “realistic” as opposed to using the term “expected”. We see no justification to change an already familiar and understood term by the industry.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Part 4.3 is not required. The information being asked for can be gleaned from the preceding Parts. “How” should not be in a requirement.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
PJM believes additional clarifying language is needed. Suggest the following language which is taken from the Explanation of Proposed Revision for R4.3: (4.3) Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch as anticipated within the operations time horizon;	

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We do not agree with the use of “realistic” in place of “expected”. As a general practice, personnel conducting SOL calculations would usually assume anticipated system conditions for the period that the SOL would apply. Every assumed condition is “anticipated” or “expected” based on the information available at the time of SOL calculation. If the intent is to assess potential risk if the anticipated or expected conditions do not materialize, then a more appropriate stipulation could be: “a range of expected….”. Keeping it simple with “expected” will achieve the intent of calculating SOL that is valid for the expected conditions. To force an entity to re-calculate the SOL, an additional requirement could be to stipulate that the methodology presents the conditions under which the SOLs are valid. This is in fact a general practice for most entities that currently calculate SOLs.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	No
Document Name	

Comment

Concern: The term “realistic” is vague and not measurable. We agree “…that “unrealistic” stressing scenarios may be more of an academic exercise to “break the system” and may not translate to actual operations preparedness.”

Suggestion: We offer the following revisions for consideration.

Describe how instability risks are identified, considering **historical and future loadings** of transfers, Load and generation dispatch.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	

Overall I really like the intent of the requirement.

I read Realistic as "Expected". Now that I've read this and think about that was my mistake, however I won't be the only one to not think deep enough into what I'm reading. So I believe a little more clarification would help even if it's in technical supporting material like the TOP standards used.

If the intent is to require the RC to look at more than expected, then a little more language is probably called for.

For example, specify that not just expected but also realistic stressed condition such as different load levels, transfer conditions, typical nonfirm, typical (but not expected) generation patterns, etc should be run. (It could also be lower load or lower transfer). It should also allow the RC room to specify unrealistic conditions if they want, if someone is willing to undertake the exercise we should not preclude them if they find value in it. The requirement could follow the TPL 001-4 model of requiring that the RC select one or more sensitivities "expected to stress the system" be run in addition to the base expected conditions.

Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

We do not agree with the use of "realistic' in place of "expected". As a general practice, personnel conducting SOL calculation would usually assumes anticipated system conditions for the period that the SOL would apply. Every assumed condition is "anticipated" or "expected"

based on the information available at the time of SOL calculation, hence nothing is "realistic" until real-time. If the intent is to assess potential risk if the anticipated or expected conditions do not materialize, then a more appropriate stipulation could be: "a range of expected….". Even with that, it will become an argument when it comes compliance audit time whether or not the responsible entity looks and if not, why not. Keeping it simple with "expected" will achieve the intent of calculating SOL that is valid for the expected conditions.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SMEs would like to Change to NO. Wording should be changed to read: *Describe how instability risks are identified, **considering realistic maximum and minimum** levels of **expected** transfers, Load and generation dispatch*	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
We support using the qualifier "realistic" in Part 4.3.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment	
A lot more transfer impacts fall within the “loop flow” category and therefore by stating “realistic transfers”, it is all encompassing. By including a reference to firm and non-firm transfers, entities may only include transmission service that they have sold and not all transfer impacts on their system.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
The term realistic is sufficient	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Recommend that “severe but credible” is another alternative to “expected”.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] The use of the word 'realistic' should be sufficient.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	Yes
Document Name	

Comment

WAPA agrees with the intent and suggests more clarification should be added in the RC's Methodology and Outage Coordination documentation, i.e. The terms: "realistic levels of transfers", "consider", and "unacceptable quantity" are subject to interpretation.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

The use of the word 'realistic' should be sufficient.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

The use of the word 'realistic' seems appropriate.

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The term "realistic" is sufficient.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	

Comment

Realistic is better than "expected". “Credible” would also be appropriate and is used in other standards.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA agrees with the term “realistic”. We do not feel additional language is needed.

Likes 0	
Dislikes 0	

Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The term “Realistic” is too vague, and may allow entities to apply a single scenario to all of its assessments. Texas RE recommends using the term “Anticipated” as it implies that the entity will apply forecasted conditions to its assessments. In this scenario, “Anticipated” is stronger language and would require entities to apply current conditions to its assessments.	
Likes 0	
Dislikes 0	
Response	

12. With regard to proposed Part 4.5: Current FAC-011-3 Part 3.1 requires that the study models include the entire RC Area. However, the SDT believes that it is not necessary for reliability that the entire RC Area is studied; instead, the area modeled may vary depending upon the facts and circumstances of the particular footprint or electrical area. Should Part 4.5 require the anything different for description of the study model used? If so, what should else be included and why?

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We believe not specifying the "entire RC Area" does not leave any reliability gap since a responsible entity needs to consider the reliability impact on its own and adjacent area when it determines the SOLs.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No
Document Name	

Comment

Part 4.5 is not required. The information being asked for can be gleaned from the preceding Parts. "How" should not be in a requirement.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy agrees with the SDT that it is not necessary for reliability that the entire RC Area is studied. We recognize the flexibility that would be provided allowing an entity may choose to model a smaller area, or model the entire RC Area if necessary.

Likes 0	

Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Current description is sufficient. Manitoba Hydro agree that it is not necessary for reliability that the entire RC Area is studied; instead, the area modeled may vary depending upon the facts and circumstances of the particular footprint or electrical area	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Part 4.5 is adequate as currently worded.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
We believe not specifying the "entire RC Area" does not leave any reliability gap since a responsible entity needs to consider the reliability impact on its own and adjacent area when it determines the SOLs. **Note: ERCOT does not support the above comment**	

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	

Comment

FAC-011 should not require that the study models used for SOL establishment include the entire RC Area.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

The proposed 4.5 is appropriate regarding the study model description, but the allowed use of RAS should be in a separate requirement (see next question) and the study model is relevant to all SOLs, not just stability.

Likes 0	
Dislikes 0	

Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. We request that the team review the inclusion of non-BES data and Facilities as is currently being included in a revision to TOP-001 (Project 2016-01). The RC should address whether or not those facilities may be required to be included in the model also, as determined by the TOP.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We request that the team review the inclusion of non-BES data and Facilities as is currently being included in a revision to TOP-001 (Project 2016-01). The RC should address whether or not those facilities may be required to be included in the model also.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The entire RC Area should be Studied and Stable and the question (not the Standard) implies that RC does not have to study its entire Area which is incorrect. As the Standard is written WAPA agrees that a finer detailed study would be more applicable as the conditions arise.	
Likes 0	
Dislikes 0	

Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] We request that the team review the inclusion of non-BES data and Facilities as is currently being included in a revision to TOP-001 (Project 2016-01). The RC should address whether or not those facilities may be required to be included in the model also.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
‘realistic’ is an adequate descriptor.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS recommends that the requirement 4.5 be deleted entirely or defer responsibility for the study model details to the TOP.	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
I think 4.5 is almost perfect. I do wonder if RAS should get a little more description on what you mean. For example is the intent to allow the RC to decide if the SOL limit should be set to avoid RAS triggering or allowing for RAS triggering? If so maybe that should be a little more descriptive. There is too much diversity among the RC systems to be specific in what the model should include. In some cases, it might even make sense for an RC to have multiple smaller models that give them a better range of results for the same investment then a single large model would. As written 4.5 allows that and the measure should be written accordingly.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not agree that the entire RC Area should not be studied. Study models should include the entire RC Area in order to determine the consequences of any actions that may be taken to mitigate instability issues.	

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	
Document Name	

Comment

NO!

Likes 0	
Dislikes 0	

Response

13. With regard to proposed Part 4.5: The requirement specifically identifies Remedial Action Schemes (RAS), however other protective schemes (such as UVLS and UFLS) and their impact on stability performance were not included. Should the requirement specifically identify other types of protective schemes? If yes, please describe why.

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Use of UVLS and other scheme should be allowed for their intended use but should not be required. For example, UVLS should be allowed for multiple or extreme contingencies.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
No, but language should be added to include any other study schemes that could have an impact upon stability performance.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Part 4.5 is not required. The information being asked for can be gleaned from the preceding Parts. “How” should not be in a requirement.	
Likes 0	
Dislikes 0	

Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
If the system maintains stability these schemes should not play a significant role in determining an SOL.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] The RC can still dictate the allowed uses of UVLS and UFLS in relation to SOLs without it being in the standard, correct?	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The RC can still dictate the allowed uses of UVLS and UFLS in relation to SOLs without it being in the standard, correct?	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. The RC is allowed to direct uses of UVLS and UFLS in relation to SOLs without it being in the standard.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
This will cause more confusion and burden than benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No

Document Name	
Comment	

Proposed change: Stability Analysis should also be aware of UVLS and UFLS. However as stated by FERC should not be used to set stability limits.

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
It would make sense to include UVLS since many of them are installed to prevent voltage instability resulting from credible multiple contingencies. But UFLS could be excluded since the unacceptable frequency response mitigated by UFLS is typically caused by multiple contingencies associated with extreme events.	
Likes 0	

Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The requirement should include reference to other protective schemes, such as UFLS and UVLS so the full event is considered when determining stability SOLs.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Since UVLS action can improve voltage stability, it should be considered in identify stability limitations.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Regardless if the assumption is that UVLS/UFLS are the Interconnection wide safety nets and not a part of identified local uvls/ufls the stability assessment should still consider their impact.	
Likes 0	
Dislikes 0	

Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
A separate requirement should address the allowed use of RAS and other protections schemes (including UVLS and UFLS) in SOL determination. This should include the description of the allowed loss of load (consequential/non-consequential, single versus multiple contingencies, adverse system conditions, etc.). A mapping is required with FAC-011-3 R2.3. In any case, RAS and other protection schemes should be addressed for the different types of limits, not just stability limitations.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
The SDT should consider using broader language here rather than limiting the application of R4.5 specifically to RAS. One suggestion is to use the phrase “automatic post-Contingency mitigation actions”, which could include any automatic action that is designed to render the system in a state of acceptable post-Contingency system performance upon occurrence of identified Contingency event(s). The RC’s SOL Methodology could then address UVLS and UFLS in their SOL Methodology as they deem necessary.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that UVLS, UFLS and runback schemes should be included, as these types of actions are included in the contingency definitions which allow for increased transfer capability.	

Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
YES. Other types of protective schemes can have significant impact on system performance. UVLS and UFLS can prevent cascading. Automatic load restoration and switching schemes can significantly vary expected system conditions post-contingency. The wording should be changed to be*: Include a description of the study models, including the level of detail that is required and the* ***use of protective isolation and load restoration schemes.***	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	
Document Name	
Comment	
If the intent that the SOL should be set to avoid UVLS and UFLS activation for a range of realistic system conditions, then that should probably be specified somewhere. I believe the UVLS is mentioned in the system voltage limits, but perhaps should be addressed in this later section as well.	

Likes 0	
Dislikes 0	
Response	

14. With regard to proposed Part 4.6: Do you agree that the RC SOL Methodology should specifically address this issue?

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
It should also include adjacent systems in other RCs.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Part 4.6 is not required. The information being asked for can be gleaned from the preceding Parts. “How” should not be in a requirement.	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
The RC SOL methodology will define stability limitation as proposed in R4. Why would it vary from one TOP to other?	
Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
R4 already requires a description of the method used in operations to determine stability limitations. R4.6 is not necessary.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No

Document Name	
Comment	
This will cause more confusion and burden than benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
It will force communication of potential issues between TOP areas in determining SOLs and identifying a common limit.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

I believe the SME's changed this vote to NO. Stability limitations should be established the same way no matter how many TOP’s are effected.

Likes 0	
Dislikes 0	

Response

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee

Answer	Yes
Document Name	

Comment

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	Yes
Document Name	

Comment

Yes. As written, this gives quite a bit of flexibility to the RC to handle their different areas. In some areas it may be sufficient that the RC Specify that both TOP's agree to the limit, and in other areas the RC may need to be more specific in how that is done. The ideal situation for some requirements is that the encourage correct behavior, without ever actually being invoked.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment	
BPA believes criteria specifically addressing stability will allow for consistency amongst TOPs in a regional area.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

15. Do you agree that the RC should continue to have a process to specify the multiple contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation?

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Transmission operators and planners are most knowledgeable of their system. Therefore, it is best to leave the task of coming up with contingencies to planner and operators. What additional role the RC can play in this regard is not clear.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Sub-Part 4.2.2 addresses multiple Contingencies, and refers to Requirement R5. Requirement R5 is a “how” requirement, and not needed. Sub-Part 4.2.2 should be revised to remove the reference to Requirement R5.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The RC should have a process to specify the multiple contingencies that should be considered in the calculation of SOL, which is more precise than just saying “used in the evaluation for potential System instability, Cascading outages or uncontrolled separation”. The intent is that the RC needs to consider multiple element contingencies in its assessment when calculating SOLs and IROLs, which are applied in real-time, to prevent System instability, Cascading outages or uncontrolled separation. Evaluating the potential for such occurrences does not drive home the notion of what’s presented in the explanation column, namely, to “establish stability limitations and IROLs”. We therefore	

suggest R5 be revised to:

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the calculation of SOL to mitigate the potential for System instability, Cascading outages or uncontrolled separation.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	No
Document Name	

Comment

Is the intent to REQUIRE every RC to have a method of determining multiple contingencies and including them? Alternatively, is the intent to give them permission to do so? If the intent is to give permission, but not require, then the requirement needs to be a little less directional or the measure could identify that an acceptable "method" is to not have any.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

We agree that the RC should have a process to specific the multiple contingencies that should be considered/applied in the calculation of SOL, but not in "the evaluation for potential System instability, Cascading outages or uncontrolled separation". The intent is that the RC needs to consider or include in its assessment when calculating SOLs and IROLs which are applied in real-time to prevent System instability, Cascading outages or uncontrolled separation. Evaluating the potential for such occurrences does not drive home the notion of what's presented in the Explanation column, namely, to "establish stability limitations and IROLs". We therefore suggest R5 be revised to:

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the calculation of SOL to mitigate the potential for System instability, Cascading outages or uncontrolled separation.

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

No opinioin

Likes 0	
Dislikes 0	

Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment
Texas RE recommends this Requirement include additional details about what must be included in the RC's method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation. As this Requirement is currently written, an RC would be allowed to create a method that would not identify any multiple contingencies, and therefore no multiple contingencies would be considered.

Likes 0	
Dislikes 0	

Response
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]

Likes 0	
Dislikes 0	

Response
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

We agree and have no additional comments.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	

Specifically related to Operational Credibility vs Planning Credibility for Multiple Contingencies as these two are not the same.	
Likes 0	
Dislikes 0	
Response	

16. The multiple contingencies referenced in Requirement R5 relate to those stability limitations established under Requirement R4, some of which may be IROLs, while others may not. The intent of SDT was to allow the RC flexibility in developing its RC SOL Methodology so that it can use the list of multiple Contingencies in a manner that is broader than solely for use in establishing IROLs. For example, the multiple Contingencies can be used by the RC in identifying the conditions referenced in Requirement R8. Additionally, the RC could use the multiple Contingencies in its OPA to identify potential instability and Cascading outages. Do you believe an additional requirement is necessary to specifically identify how an entity would implement the multiple Contingencies? If yes, please provide the specific language you propose for the requirement.

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Document Name	
Comment	
How multiple contingencies are used should be left up to the RC.	
Likes 0	

Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
We do not think that a separate requirement to specify how an entity would implement the multiple Contingencies given that Requirement R5 already stipulate the need to include multiple contingencies in SOL calculations (especially with our proposed language change). **Note: ERCOT does not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
The proposed language allows for adequate flexibility for the RC’s SOL Methodology.	

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

“how an entity would implement the multiple Contingencies” should be addressed in the guidelines. Addressing the methodology for performing OPA and RTA, if necessary, should be addressed elsewhere, probably in a distinct standard.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	

Comment

An additional requirement isn't necessary to specifically identify how an entity would implement the multiple Contingencies. NERC standards are to address "what" and not "how". Specifying "how" isn't flexible nor useful in a mandatory standard.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Please see our answer to question 15.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The TOP(s) should identify the Credible Multiple Contingencies and implementation used in the Operations time frame in question.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
A requirement specifying when and how multiple contingencies should be evaluated fits better with TOP-001-3 than with this Standard. These multiple contingencies should be evaluated in the OPA and RTA, especially with the proposal to remove the planning horizon from the SOL definition.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
"The Reliability Coordinator shall describe how the multiple contingencies identified in R5 will be used by the RC and TOP for identifying SOLs and	

IROLs.”

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	Yes
Document Name	

Comment

Does the current R5 allow for the monitoring of a double within the OPA and in real time for finding potential system instability, cascading outages or uncontrolled separation? If so, does that monitored double also have to meet the Facility ratings (SOL Exceedance) criteria?

For example can a RC monitor a common structure and not react if it is over its emergency rating as long as there is no risk of potential system instability, cascading outages or uncontrolled separation as defined by the RC?

For that matter if an RC or TOP decides to monitor a Multiple Contingency, does that obligate them to list it under R5 and meet that criterion?

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

17. Do you agree that the RC SOL Methodology should be required to include *all* of the criteria included in proposed Parts 6.1 through 6.4? Do you believe there are additional criteria that are not currently included, but should be?

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
IT depends on the RC footprint.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Requirement R6 should not specify the method ("how"). In the Parts for Requirement R6, what is unacceptable?	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
6.4 is a catch all that captures 6.1 – 6.3. Therefore listing 6.1 – 6.3 is not necessary. However, if industry feels that this is required, then a subpart should be added to reflect "unacceptable loop flow" through neighboring systems.	
Likes 0	
Dislikes 0	

Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

We agree with the intent of R6, but we think it deserves some rewording:

1- 6.3 could be limited to “Unacceptable inter-area oscillations”. However, we don’t think 6.3 captures the “non-localized or uncontained instability” concept described in the explanation.

2- Unacceptable quantity of load loss (or supply loss) should be independent of “due to “System instability, Cascading outages or uncontrolled separation”. An unacceptable quantity of load loss (or supply loss) can itself cause “System instability, Cascading outages or uncontrolled separation”. What if a system condition makes the loss of a major transformer a contingency for which the “Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs”…which could overload another transformer beyond its protection setting, that would then trip and cause an unacceptable quantity of supply loss? Thus, we suggest combining 6.1 and 6.2 with “Unacceptable quantity of load or supply loss” and removing the reference to instability, etc.

3- A bullet should be added to specifically address unacceptable “System instability, Cascading outages or uncontrolled separation” (that would cover the “non-localized or uncontained instability” concept) in relation with the definition of IROL.

Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No additional criteria are necessary.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
No additional criteria needed.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
The acceptable amount of load or supply loss should be determined by TOP and not by RC. This is because much depends upon the size of the TOP	

total load and the specific operational and topographical aspects of the TOP's system. For example, a 500 MW load loss in a metropolitan city may not be large enough to cascade; however, the same load loss in a rural area could be large enough to cascade. Because TOPs are most familiar with their systems and associated operations, the determination of the acceptability of a certain amount of load or supply loss should be determined by the TOP. AZPS recommends that the SDT revise this requirement to reflect this.

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The proposed criteria are fine.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] Yes it should be included. Nothing else is needed	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Yes it should be included. Nothing else is needed.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

1. Yes, we agree that all criteria should be included.
2. No, we do not believe anything additional is needed.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA believes no additional criteria are required.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	Yes
Document Name	

Comment

I think R6 is good as written, however changes should be considered as the team reviews the results of surveying the RC's IROL methodologies. The

Requirement or Measure should specify that the unacceptable quantity of load can be a set MW value, a percentage of system load, or could even be a different value for different areas of the system. In our region we have TOP's that only have 800 MW of load, and TOP's that consider an 800 MW substation a medium size substation. Therefore, a one number for the whole region may not set a meaningful threshold for everyone.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

18. Should the criteria identified in proposed Parts 6.1 through 6.4 also include a minimum or maximum threshold? If so, what should the thresholds be, and why?

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern believes that the criteria should be left to the RC to define. However, if the SDT were to establish the criteria, we believe that the minimum criteria should be established in generic terms to give RCs in different geographical areas the flexibility to define the criteria themselves.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. Each RC's needs may be different. Including minimum or maximum criteria to the statements would create a one size fits all areas which would not be appropriate across the Interconnections. As well the criteria across a single RC Area may not be appropriate do to the vast differences within the RC's Area. (Example: The criteria used around critical Load areas such as major Department of Defense facilities might not be the same as sparsely populated areas where there are hundreds of square miles - might not qualify under the one size rules.)	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Each RC's needs may be different.	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The thresholds are best left to each RC according to its area's consideration, criteria and restrictions.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] Each RC's needs may be different.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
No, establishing a hard minimum and maximum could be counter-productive to reliability since facts and circumstances determine the appropriate values.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The RC should determine appropriate thresholds.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Again, it depends on the RC footprint. There needs to be some latitude/discretion for the RC to make the best decisions for its footprint.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Giving RC the discretion to determine what thresholds are most suitable for its RC Area would be best.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	

Answer	No
Document Name	
Comment	
The thresholds are best left to each RC according to its area's consideration, criteria and restrictions. **Note: ERCOT does not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
There is an enormous range of system sizes across the country. Setting a range that is meaningful for an TOP whose peak load is 800 MW but is also meaningful for a TOP that find 800 MW to be a typical substation would result in such a large range as to not be of value. A percentage might be of more value, however the same scaling factor occurs. A threshold of 10% would result in a TOP with only 10 substation to not be able to lose one station, and by the same token might mean 20 substations for an entity with two hundred stations. Perhaps a threshold based on substations, rather than MW. That you are not allowed to lose more then so many stations be in generation or load. Or perhaps set a range, but allow exceptions with explanation.	

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
While prescribed thresholds would improve clarity and consistency for IROL establishment, doing so might also have an unintended consequence of undermining the flexibility needed for RCs to address the unique situations and challenges in the RC Area.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Definitely not. This is way too system specific. It is the responsibility of the RC to define such thresholds. However, guidelines to explain the industry practice regarding this topic would be appropriate.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
The criteria identified in proposed Parts 6.1 through 6.4 should allow for Regional and Local variances regarding determination of a minimum or maximum threshold.	

Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

The minimum threshold should be 1% of the RC area peak load, and a maximum threshold should be 10% of the RC area peak load. This is based upon the fact that we are dealing with multiple contingencies and loss of less than 1% of the RC area peak load loss should be acceptable and not be called cascading.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

6.1 wording: Unacceptable quantity of load loss equal to 500MW or greater due to System instability, Cascading outages or uncontrolled separation. This value is 2.5 times the EOP-004 firm load loss reporting requirement and represents significant impact to the public.

6.2 wording: Unacceptable quantity of supply loss greater than the value of the interconnection's MSSC due to System instability, Cascading outages or uncontrolled separation. This is based on a loss bigger than an interconnections MSSC.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has no comments on this question.

Likes 0	
Dislikes 0	

Response

19. Do you believe the IROL Tv definition should be modified to remove the 30 minute not-to-exceed time limit, and instead the specific time limit should be identified in the specific Reliability Standard requirement, as appropriate?

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We are not in a position to provide feedback on modifying the IROL Tv definition until we review the revised IROL definition being proposed.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The 30 minute maximum time limit is appropriate for IROLs.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
The time limit can remain in the IROL Tv definition and reside within R7 as proposed.	
Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
No, the IROL Tv definition should not be modified to remove the 30 minute not-to-exceed time limit.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
30 minutes is still a good value.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No

Document Name	
Comment	
We agree with the proposed R7 and with the IROL Tv definition.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
No, the IROL Tv definition should not be modified to remove the 30 minute not-to-exceed time limit. Rather, the proposed R7 should have that last sentence removed. **Note: ERCOT does not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
For IROLs identified in real-time the 30 minute threshold does not give the operators much time to assess the situation and could lead to load-shed for non-IROL exceedences. In some instances such as real-time identified IROLs versus pre-defined IROLs, a greater than 30 minute Tv could be warranted and should be allowed.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
The 30 minutes limit on Tv is arbitrary and should be eliminated.	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Establishing all critical time to be no longer than 30 minutes; may not be realistic depending on the viability of the contingencies required to fulfill the IROL. If a Tv has not been established than using the no longer than 30 minutes would be appropriate.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
It is redundant to the Glossary Terms as well.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
NIPSCO believes the 30 minutes belongs in the specific Reliability Standard requirements.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	Yes
Document Name	

Comment

1. With the criteria not set with firm minimums and maximums in (Requirement R6) to allow flexibility in IROL's, the same should be allowed in determination of the allowable time associated with the IROL.

2. IROL's should not have a maximum time limit of 30 minutes established. The Tv time frame was established to allow the appropriate time to be associated with the IROL in question. Establishing all critical timeframes to be no longer than 30 minutes may not be realistic, depending on the viability of the contingencies required to fulfill the IROL. Where a Tv has not been established, using the "no longer than 30 minutes" requirement would be appropriate.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	Yes
Document Name	

Comment

We do not see strong technical rationale for having the 30 minutes threshold. We consider the broader Tv definition to be more appropriate.

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	Yes
Document Name	

Comment

Peak supports having the IROL TV as a requirement and removing it from the NERC definition of IROL TV.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Alternatively, the standard could set a default maximum of 30 minute but allows greater than 30 minutes with an explanation.	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
No!	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

20. Do you agree with the proposed approach for addressing this Real-time operating state issue?

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We agree with having a requirement to address real-time situations where the need for a new or revised or re-confirmed set of SOLs needs to be established, when operators encounter an unknown or unstudied state. However, we feel this should be done such that actions can be taken to return the system to a known state within 30 minutes.

This was the intent of Requirement R4 of the retired TOP-004-2. While the IRO/TOP SDT for the TOP-001 to TOP-003 standards rationalizes that between the definitions of OPA, RTA and some FAC standard requirements, the potential reliability gap due to the absence of valid SOLs for unknown or unstudied conditions is duly addressed, we do not believe that's the case especially for those situations where the SOLs or IROLs are restricted by system stability limitations.

While today's technology can be relied upon to calculate facility rating restricted and voltage restricted SOLs/IROLs in real-time, it has not yet advanced to the point where stability-restricted SOLs/IROLs can be calculated real-time or within the 30-minute time frame to allow for (a) comparing system conditions with the re-established SOLs/IROLs, and (b) applying control actions to return the BES conditions to within the re-established SOLs/IROLs.

That said, we propose to simplify R8 by revising it to:

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state which falls outside of the scope of established SOLs where it is uncertain if any existing SOLs are valid. The method shall address:

1.

   i. **Thresholds for initiating evaluation or validity of existing SOLs;**

   ii. **A review of whether a new set of SOLs or IROLs should be established;**

   iii. **A process for deriving any required SOLs or IROLs such that exceedances are resolved within 30 minutes.**

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	

The condition in this requirement " but was not identified one or more days prior to the current day " is unnecessary as when the next contingency has the potential to cause System instability, Cascading outages or uncontrolled separation the condition should become an IROL if it meets the IROL criterion specified in R6. It is not clear that what difference in operating actions or evaluations will be whether the condition was identified in prior studies or not. If a condition was identified in prior studies other standard requirements require RC/TOP to have an operating plan to mitigate such conditions. If the conditions shows up in RTA the RC/TOP will still need to evaluate and take actions. Whether operating condition constitute and IROL exceedance or not should be determined using criterion specified in R6. If the operating condition is indicating an IROL issue than it should be treated as IROL which in turn will require system operator to act with urgency.

This requirement can possible be combined with R6 by requiring RC to specify in SOL methodology criterion when an SOL can become temporary IROL.

Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS agrees with Requirements 8.1 and 8.2, but does not agree with Requirement 8.3. The criteria for declaring an IROL is clear and does not require a review of a real-time event to make the determination.

Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

We agree with having a requirement to address real-time situations where the need for a new or revised re-conformed set of SOLs needs to be established, and how it can be developed. This was the intent of Requirement R4 of the retired TOP-004-2. While the IRO/TOP SDT for the

TOP-001 to TOP-003 standards rationale that between the definitions of OPA, RTA and some FAC standard requirements, the potential reliability gap due to the absence of valid SOLs for unknown or unstudied conditions is duly addressed, we do not believe that's the case. The proposed Requirement R8, despite it's mixing operations with methodology, appears to fill this potential gap nicely.

That said, we propose to simplify R8 by revising it to:

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state which falls outside of the scope of established SOLs or where it is uncertain if any existing SOLs are valid. The method shall address:

Please consider replacing references to SOL in R8 with stability limitations.

8.1 Thresholds for initiating evaluation of validity of existing SOLs;

8.2 A review of the operating state experience for the purpose of determining whether a new set of SOLs or IROLs should be established.

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

R8 is outside the scope of FAC-011 and any gap regarding this topic should be included in the TOP/IRO standards. In 8.2, the mention of "pre-Contingency Load shedding" is the only occurrence within the proposed standard and explanations. We think that an unknown operating state should be treated differently from an IROL violation.

A gap was introduced with the removal of TOP-004-2 R4 (If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and

shall restore operations to respect proven reliable power system limits within 30 minutes). The situation where, for a specific IROL interface, the System conditions in real-time were not studied to calculate a IROL value is an unknown state for which no specific action is required under the new TOP/IRO standards. Unless real-time stability tools are available, the RTA is not useful to evaluate the stability risk for the unknown state.

The language is sloppy too. 'shall address', the last point has a different time frame and is actually an obligation to review…

Given the argument we make, is only the last point relevant then? The methodology should include a description to review irself following insecure states that occur?

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

1. We agree with the approach to distinguish actual IROLs from these other types of unexpected events; the language doesn't establish a limit, but allows the operator to react quickly and then review the occurrence to learn how to deal with something similar in the future.

Likes 0	

Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
R8 language could be refined by replacing "one or more days prior to the current day" with "prior to the operating day". This is for situations not identified prior to the operating day. R8.3 should include the proposed timeline for the review with a suggestion that it take place within 10 business days of the event.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
I like the approach, though I am open to more discussion on the specific wording.	
Likes 0	

Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

21. Do you believe there should be a timing requirement for implementing actions to address the risk (*e.g.*, 30 min)? If yes, when should the time start? End?

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
No timing requirement for risk mitigation actions is necessary - this reliability objective would be better addressed by having a reciprocal TOP or IRO requirement that requires implementation of the mitigation action in accordance with Q23.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The Real-time event may not have a clear initiation or clear resolution. Applying time limits may push TOPs to take more severe actions than necessary to meet an arbitrary time limit.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
We think there should be a requirement to have an Operating plan to mitigate this risk rather than a specific time. An Operating plan should be required to address unforeseen System conditions and topology for which an IROL cannot be calculated because it was not studied for this condition. The exact timing would depend on system conditions and specific issues encountered.	
Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
While Peak understands the value of mitigating an unanticipated N-1 insecure state within 30 minutes, there can be unintended negative consequences for having a 30 minute requirement. When such conditions arise, there is a certain amount of validation that needs to take place before actions are taken, especially when drastic mitigating measures are considered such as load shedding. Unlike pre-determined IROLs which are monitored in real-time operations, it is unclear exactly when the "clock starts" for such conditions. When faced with ambiguous operating conditions while being under the pressure of a fuzzy-at-best 30-minute compliance clock, operators might be inclined to take drastic and unwarranted measures to mitigate the perceived condition, such as load shedding, to avoid a compliance violation – even when the complete operating picture is unclear. Given the potential for such a negative unintended consequences, Peak is not supportive of adding timing requirements for mitigating such conditions.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Timing will vary based on the event. BPA Believes it is up to the TOP to develop an Operating Plan that meets the needs for its system for all conditions.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
But more time (greater than 30 minutes) should be given to the operators to properly analyze the situation and decide what actions to take. A 30 minute time limit could be too restrictive and cause the operators to potentially shed load for non-cascading situations. The time should start at the "time of discovery" and end when the situation has been mitigated or the potential for cascading outages removed.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	

Comment
While AZPS agrees that this requirement should have a time-based aspect, it does not agree that the requirement should be completely time-based or that the measure of compliance should be based on pass/fail criteria. More specifically, each system event that occurs is associated with and subject to the unique system characteristics and constraints in effect during that time. As such, operators should be given flexibility and a range of actions that can be taken to reduce the potential impact and likelihood of the next contingency. In particular, where operators are able to take action to significantly reduce the potential for or impact of next contingency, such actions should be considered acceptable for the purposes of compliance under this requirement. The Relative to the time-based aspect of this requirement, such time period should start at the end of the expiration of the time period for the Tv and, further, an additional time period of 30 minutes should be allowed to evaluate the impact of actions taken.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	

Comment
Yes, a 30 minute timeframe is appropriate. It should begin when the risk is identified.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	

Comment
The time to implement actions should be aligned with the time frame associated with the ratings. For example, a line has normal, emergency and short term emergency (STE) ratings where emergency rating is a 4 hour rating and a 30 minute short term emergency. If the flows on this line exceed emergency rating but are below STE the Operating Plan to bring flows below or at emergency rating should be implementable within 30 minutes. The time should start when the real-time or post contingent flows exceed a specified SOL and end when the flows are reduced below the SOL. The criterion should also allow for some time to validate the issue to ensure that the exceedance is valid before the timer starts.

Likes 0	
Dislikes 0	

Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Consistent with R7, less than or equal to 30m. Timing would start from the identification of the Real-time operating state. If, by "End", you are refrencing the Tv, it would end 30m after the start, unless the RC's methodology elected to reduce that timeframe.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] Providing a time would give clarity to when situations cross over into ‘violation’ territory instead of just being an exceedance.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The timing should be 30 minutes such that the evaluation of the prevailing situation, establishment of a validated or revised/new set of SOLs/IROLs, and implementation of appropriate actions to mitigate SOL exceedances are all completed within the general Tv (or 30 minutes) time frame.	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Providing a time would give clarity to when situations cross over into 'violation' territory instead of just being an exceedance.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. Providing a time would give clarity to when situations cross over into 'violation' territory instead of just being an exceedance. 2. With SOL being elevated to a "temporary IROL;" the timing for action should be similar to those of an established IROL for the RC Area. The only exception would be that the Tv may not be readily known from the available real-time studies. In this case the 30 minutes maximum time would be more appropriate.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
We believe that a timing requirement for implementing actions to address the risk should be part of operating protocols.	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
Yes!	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Actions should be taken immediately after the operating state is identified. A maximum of 30 minutes may be acceptable, as it aligns with the IROL-Tv.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	

Answer	
Document Name	
Comment	
Assuming this question is specific to the real time operating state issue: I do not think an arbitrary timing requirement is wise. In some cases, taking an action based on incomplete analysis could result in worse condition then taking no action. Alternately, a requirement could be added that the RC does an internal investigation if they take more than 30 minutes to complete their analysis and take action to shorten the time in the future?	
Likes 0	
Dislikes 0	
Response	

22. Do you believe that this issue is already addressed in other Reliability Standards (*i.e.*, IRO-009 and EOP-011)? If not, should it be?

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. We appreciate the clarification, and believe the other standards are loosely related to this situation but do not fully address this.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

It is good to clarify it here. Those other standards are probably loosely related to this situation.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

No, we do not believe this issue is already addressed elsewhere. Please see our comments under Q20, above.

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It is good to clarify it here. Those other standards are only loosely related to this situation	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Residing within FAC-011-4 is sufficient.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
No, but addressing in the FAC standard should be sufficient.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	

The IRO-009 and EOP-011 standards address what action the RC or TOP shall take to prevent an IROL Exceedance. This requirement addresses how to find if an RC has an IROL. It should be address in this standard as this standard is about methodology to determine SOLs and IROLs. The other standards are about actions that should be taken.

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	

Yes, it should be.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	
Comment	

The RC's Methodology is the most appropriate place to address this issue.

Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee

Answer	No
Document Name	

Comment	
No, we do not believe this issue is already addressed elsewhere. Please see our comments under Q20, above. Further, we believe this issue should be addressed here in FAC-0011 since the TOP standards are not going to change given the SDT's response to our comments and FERC's position in its Order 817. **Note: ERCOT does not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Peak believes it is not adequately addressed and it should be addressed directly outside the IROL concept.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No

Document Name	
Comment	
The IROL exceedance and emergencies are addressed in other standards, but not the unknown or insecure operating state. EOP-011 is general enough to already address this issue. However IRO-009 could include another requirement to address this issue.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	Yes
Document Name	

Comment

The revised TOP/IRO standards have requirements that require RC/TOP to implement operating plan for actual/potential SOL/IROL exceedances. Future effective TOP-001-3 R14 requires "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment", thus if an SOL condition indicates IROL like issues the operating plan shall address those and treat those as IROL per RC SOL/IROL methodology.

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
Yes!	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	
Document Name	
Comment	
This standard is the correct place to address the current issue involving real time emerging constraints.	
Likes 0	
Dislikes 0	
Response	

23. If the proposed requirement is added, should a reciprocal requirement be added to require implementation of the method (*e.g.*, possibly a new TOP or IRO requirement)?

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
The revised TOP/IRO standards have requirements that require RC/TOP to have implement operating plan for actual/potential SOL/IROL exceedances.	
Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	

See response to Q21.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

The method does no good if it is not implemented.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	

Comment

Yes, implementation should be required, but could be added to existing TOP and IRO standards.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

We believe that a reciprocal requirement added to TOP-001 will close the reliability gap.

Likes 0	
Dislikes 0	

Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
As mentioned in Q22, IRO-009 could be revised to include this issue.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
It might be a good idea to have a corresponding requirement somewhere to implement this. The FAC standards don't seem to be the best fit.	
Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
We believe that a reciprocal requirement added to TOP-001 will close the reliability gap.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
No!	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

24. Do you agree with the proposed revisions? If not, please explain why and provide any changes that you propose to the language.

Chris Scanlon - Exelon - 1,3,5,6

Answer	No
Document Name	

Comment

On page 9 of the Summary of Proposed Revisions there are two bullets that seem to conflict with one another. Our concern is third and fourth bullets from the top of page 9 under the Proposed New Definition. The third bullet indicates an issue if the calculated post-contingency voltage calculated is outside emergency limits, however the fourth states the exact same thing except adding for which there is not sufficient time to relieve the condition.

It seems these are inconsistent with one another; we propose the SDT should delete either the third or the fourth bullet depending on whether they intend to allow operators time to relive the condition. As it's written we believe it's vague and could be interpreted differently by different engineers and operatiing organizations.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

In general 30 days to review this breadth of changes was not sufficient.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	No
Document Name	

Comment

PJM believes R9.2 should be consistent with language of 9.1. The proposed requirement places an undo burden on the RC to track each PC or TP modeling "any portion" of its area. Suggested language below:
(9.2) Each adjacent Planning Coordinator and adjacent Transmission Planner within an Interconnection, and each Planning Coordinator and

Transmission Planner that indicated it has a reliability-related need for the SOL Methodology; and,

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	No
Document Name	

Comment

No, see previous comments on specific language suggestions.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team. We fail to see the inncremental value of these changes. It is just more complexity and administrative overhead for no increase in reliability.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	No
Document Name	

Comment

R9.1 the measure or requirement should be specific that it is a formal written request from the reliability coordinator, and the reliability coordinator should not have to provide a reliability-related need.

R9.2: This requirement should be revised. Every Planning Coordinator in the Eastern Interconnection potentially models every RC in the eastern interconnection, yet there is no practical reason that every eastern interconnection RC should send it to every Planning Coordinator.   This requirement should be every PC and TP that is within the RC footprint OR that makes a formal request for the methodology.   The TP or PC should not have to prove a reliability related need.

A 9.4 should be added allowing transmission owners and generator owners to request a copy.

Should R9 also allow for placing a confidentiality requirement on the parties receiving the document?

Should R9 also include TSP's who are within the RC area or an adjacent RC Area? They are effected by how SOL's are defined.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has no comments on this question.	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
We believe that a reciprocal requirement added to TOP-001 will close the reliability gap.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
A question to the SDT. Should there be a minimum time period for how long a SOL Methodology should be in place prior to being effective?	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
The overall concept is fine; however, the SDT might consider modifying the language in proposed R9.2. Just because a PC or TP "models" a portion of the RC Area might not necessitate that they receive the SOL Methodology. Also, the RC cannot know what the various PCs and TPs include in their models.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Unofficial Comment Form for FAC-011-4

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits**. The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

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[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements	<u>Existing definition of SOL</u>: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits." Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition	operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability) • system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO	

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating; • Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition.	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an "SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to	types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • TOP-002-4 Requirement R1 - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs). • TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL)

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Question 1: Given how the revisions are intended to work together with the revised TOP and IRO Reliability Standards (including the definitions of OPA, RTA and Operating Plan), do you agree with the proposed revisions to the definition of SOL and new definition of "SOL Exceedance"? If not, please explain why you do not support the revisions, and what revisions you propose to align the definition(s) with the revised TOP and IRO Reliability Standards.

☒ Yes

☐ No

Comments: While ERCOT understands and can support the direction of the SDT, ERCOT expresses concern with the use of the word "limitations" in the term "stability limitations." This broad terminology, while offering the flexibility to consider various types of limitations, could be misinterpreted to refer to equipment-level limitations (e.g. low stability limit on a generator) rather than limitations at the system level. This should be clarified, perhaps by changing "stability limitations" to "system stability limitations." Additionally, the proposed change to the definition of SOL would render the reference to the term "facility ratings" in the definitions of Operational Planning Analysis and Real Time Assessment redundant. Removal of these types of redundancies should be addressed either in this project or a subsequent project, similar to guidance provided in paragraph 81 efforts.

Question 2: The suggested revisions would mean that the Facility Ratings, System voltage limits, and stability limitations are the actual SOLs. OPAs and RTAs are performed to determine whether these SOLs may potentially be exceeded (through an OPA) or are actually being exceeded (through a RTA). Operating Plans are developed to address "'SOL Exceedances." Do you believe the proposed revisions to the definition of SOL (and companion definition of "SOL Exceedance") allow for a clear distinction between "what the limits are" and "how the system should be operated"?

☒ Yes
☐ No
Comments:

Question 3: Do you agree with removing "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post- Contingency" concepts from the definition of SOL? If no, please explain your concerns.

☒ Yes
☐ No
Comments: There is still some confusion around assessing stability limits pre and post contingency in an OPA and RTA. These stability limits may be developed to provide acceptable post contingency performance (n-1). The SDT should clarify the definition language to ensure that it is not inferred that the OPA and RTA must be performed to assess if post contingent flows will go beyond a (N-1 determined) stability limit, (understanding you can consider multiple contingencies) or you will be evaluating for N-2.

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	

Question: None. All related questions have been incorporated below (*see*, questions regarding proposed Requirements R2, R6 and Part 3.1).

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology. • FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Question 4: Do you agree that the TOP should determine the appropriate Facility Ratings for use in operations, in accordance with the requirements set in the RC SOL Methodology? Note: This assumes the Facility owner will continue to provide the Facility Ratings to the RC and TOP as currently required under FAC-008. The RC Methodology will simply describe the manner in which the TOP determines which of those owner-provided Facility Ratings are appropriate for use in operations.

☒ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings;	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.4. Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and, **3.6.** Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Question 5: Do you agree that the TOP should establish the System voltage limits pursuant to the RC SOL Methodology, and that the proposed Requirement R3 provides sufficient clarity for what the RC SOL Methodology must include?

☒ Yes
☐ No
Comments:

Question 6: Is it clear what System voltage limits are? Does a definition for "System Voltage Limits" need to be created? A draft definition under consideration by the SDT is "System Voltage Limits: The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations." Please provide your perspective on whether, currently, it is clear what is meant by System voltage limits, and if not, what you believe to be the appropriate definition.

☒ Yes
☐ No
Comments: ERCOT is in favor of a definition to provide clarity and distinction between System Voltage Limits and Voltage Schedules. However, ERCOT recommends the SDT make additional clarifications to the draft definition that not all Facilities will have System Voltage Limits since they are typically applied to station busses to represent those devices connected to that electrical bus.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3	**Background regarding existing standards *not* under revision by SDT:** • IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3) – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • IRO-008-2, Requirement R1 – Each RC shall perform an OPA that will assess whether next day planned operations

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
4.1.1. steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator; • Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5.	Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must:	will exceed SOLs or IROLs within its Wide-area. • MOD-001-2, Requirement R1 (Part 1.1) – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **Mapping to existing FAC standards under revision:** • FAC-014-2, Requirement R6 (Parts 6.1 and 6.2) – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.	<u>Part 4.1</u> - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. <u>Part 4.2</u> - Meet the performance criteria for certain identified Contingencies (listed in the standard). <u>Part 4.3</u> - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. <u>Part 4.4</u> – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the stability limitations provided by the Planning Coordinator. <u>Part 4.5</u> – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to	• <u>FAC-011-3 Requirement R2 (Part 2.2)</u> - *[Maps to proposed Part 4.2]* • <u>FAC-011-3 Requirement R2 (Part 3.6)</u> - *[Maps to proposed Part 4.3]* • <u>FAC-011-3 Requirement R3 (Parts 3.1 and 3.5)</u> – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Question 7: Do you agree that the proposed use of the word stability "limitations" is a better choice than "limit" to capture the full breadth of all phenomena and determination methods/time frames for stability concerns?

☒ Yes

☐ No

Comments: ERCOT agrees with the use of either "limits" or "limitations" since either term can be read to encompasses additional "phenomena and determination methods/time frames for stability concerns." However, the SDT should clarify that the limits/limitations the definition identifies are those at the "system" level and does not include all limitations that may exist at the "equipment" level.

<u>Question 8</u>: With regard to proposed Part 4.1: Do you agree that the RC SOL Methodology should have criteria that consider *all* items in Parts 4.1.1 – 4.1.4? Are there additional criteria that should be included? If yes, please list and explain. Are there criteria that are included, that you believe should *not* be included?

☒ Yes

☐ No

Comments: The SDT should consider adding interconnection/area specific items to the SOL Methodology such as transient frequency response criteria. The current list should be the minimum criteria considered. This could be clarified by inclusion of the phrase "The criteria shall consider the following, at a minimum" to Part 4.1. The SDT should also clarify through guidance that inclusion of any additional criteria in the SOL methodology requires implementation of that criteria in FAC-014.

<u>Question 9</u>: With regard to proposed Part 4.2: Do you agree that the RC SOL Methodology should consider the contingencies listed in Parts 4.2.1 and 4.2.2? Are there additional Contingencies that should be included? If yes, please list and explain. Are there Contingencies that are included, but you believe should *not* be included?

☒ Yes

☐ No

Comments: Additional comments in response to Question 16.

<u>Question 10</u>: With regard to proposed Part 4.3: When instability risks are identified, there are various studies or assessments that analyze different transfer levels, load levels and generation dispatch combinations. The intent of Part 4.3 is to ensure that the RC SOL Methodology adequately describes how these various factors are considered in the identification of instability risks. In the identification of stability risks, the RC SOL Methodology should consider the levels of transfers, load and generation dispatch. Should the RC SOL Methodology include a description of any additional types of information?

a. Should proposed Part 4.3 specifically include "offline analyses"?
b. Should proposed Part 4.3 include forced Transmission and generation outages (*i.e.*, N-1-1)?
c. Should proposed Part 4.3 include planned outages (*i.e.*, all planned outages in the base case)?

☐ Yes

☒ No

Comments: Different levels of transfers, load, and generation dispatch are necessary to identify system conditions where calculation of an additional SOL may be warranted to prevent instability. Some representation of planned outages should be made in the base case, however this representation varies more the further out from Real time the study occurs (e.g. seasonal studies).

Since all planned outages do not overlap, it is common to implement some level of outages into the basecase for a particular interface to stress to more “realistic” operational levels, rather than all planned outages.

Question 11: With regard to proposed Part 4.3: The SDT used the term “realistic” as opposed to “expected” in order to perform sufficient assessment to identify potential stability risks. The SDT takes that position that “unrealistic” stressing scenarios may be more of an academic exercise to “break the system” and may not translate to actual operations preparedness. Is “realistic” transfer, Load and generation dispatch levels an adequate description or should more clarifying language be added, such as a reference to firm and non-firm transfers?

☐ Yes

☒ No

Comments: Realistic is too vague and clearer language may be necessary. ERCOT prefers the term “expected,” instead of “realistic,” however, the terms “firm” and “non-firm” may also introduce confusion. Using the term “expected” would cover “that which is reasonably expected to occur within the operations time horizon (< 1yr).”

Question 12: With regard to proposed Part 4.5: Current FAC-011-3 Part 3.1 requires that the study models include the entire RC Area. However, the SDT believes that it is not necessary for reliability that the entire RC Area is studied; instead, the area modeled may vary depending upon the facts and circumstances of the particular footprint or electrical area. Should Part 4.5 require the anything different for description of the study model used? If so, what should else be included and why?

☐ Yes

☐ No

Comments:

Question 13: With regard to proposed Part 4.5: The requirement specifically identifies Remedial Action Schemes (RAS), however other protective schemes (such as UVLS and UFLS) and their impact on stability performance were not included. Should the requirement specifically identify other types of protective schemes? If yes, please describe why.

☐ Yes
☒ No
Comments: UVLS and UFLS design are separate studies and have separate criteria addressed in other Reliability Standards. UVLS and UFLS schemes are safety nets for extreme contingencies and as such, the FAC standards are not an appropriate place to address them.

Question 14: With regard to proposed Part 4.6: Do you agree that the RC SOL Methodology should specifically address this issue?
☐ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs).	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	

Question 15: Do you agree that the RC should continue to have a process to specify the multiple contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation?

☒ Yes
☐ No
Comments:

Question 16: The multiple contingencies referenced in Requirement R5 relate to those stability limitations established under Requirement R4, some of which may be IROLs, while others may not. The intent of SDT was to allow the RC flexibility in developing its RC SOL Methodology so that it can use the list of multiple Contingencies in a manner that is broader than solely for use in establishing IROLs. For example, the multiple Contingencies can be used by the RC in identifying the conditions referenced in Requirement R8. Additionally, the RC could use the multiple Contingencies in its OPA to identify potential instability and Cascading outages. Do you believe an additional requirement is necessary to specifically identify how an entity would implement the multiple Contingencies? If yes, please provide the specific language you propose for the requirement.

☒ Yes
☐ No
Comments: ERCOT supports the creation of a requirement to utilize the required concepts identified in the ERCOT SOL methodology. ERCOT questions whether there is a need for any of the requirements identified in the SOL methodology that entities are not otherwise required to actually implement. The SOL methodology in of itself is not a NERC Reliability Standard requirement. The requirements to implement what is in the SOL methodology must reside in a NERC Reliability Standard requirement. ERCOT recommends creation of a requirement similar to existing TOP-004-2 R3 and recommends limiting the requirement to stability limitations or the situations identified in proposed FAC-011-4, Requirement R8. This will limit the potential incorrect interpretation that the OPA and RTA should assess multiple contingencies for all SOLs.

This could also be addressed by modifying the SOL definition to clarify that the requirement to assess SOL exceedances for multiple contingencies only applies specifically to stability limitations.

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R1</u> – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • <u>FAC-011-3 Requirement R3.7</u>- RC SOL Methodology must include a description of the criteria for

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.	language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	determining when violating an SOL qualifies as an IROL

Question 17: Do you agree that the RC SOL Methodology should be required to include *all* of the criteria included in proposed Parts 6.1 through 6.4? Do you believe there are additional criteria that are not currently included, but should be?

☒ Yes

☐ No

Comments: ERCOT requests that the SDT retain the phrase "within an Interconnection" portion of 6.4. There is currently a lack of universal direction and clarity in what the terms "neighboring" and "adjacent" mean for ERCOT and entities in the ERCOT interconnection when dealing with functional entities in two different Interconnections. Retaining the phrase "within an Interconnection," language helps mitigate this confusion.

<u>Question 18</u>: Should the criteria identified in proposed Parts 6.1 through 6.4 also include a minimum or maximum threshold? If so, what should the thresholds be, and why?

☐ Yes

☒ No

Comments: ERCOT believes that each RC has the technical understanding and rationale for determining the appropriate thresholds for mitigating risk for its RC area and subsequently setting the appropriate thresholds.

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R3.7</u>- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

<u>Question 19</u>: Do you believe the IROL T_v definition should be modified to remove the 30 minute not-to-exceed time limit, and instead the specific time limit should be identified in the specific Reliability Standard requirement, as appropriate?

☒ Yes

☐ No

Comments: Yes, the IROL Tv definition should be modified to remove the 30 minute not-to-exceed time limit. Requirements should reside in a NERC Standard and not within a definition.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

<u>Question 20</u>: Do you agree with the proposed approach for addressing this Real-time operating state issue?

☐ Yes
☒ No

Comments: ERCOT believes that there should be corresponding IRO/TOP/EOP requirements to implement the "method" referenced in R8 as part of this project. Failure to create accompanying requirements simply imposes an administrative requirement with no performance obligation.

<u>Question 21</u>: Do you believe there should be a timing requirement for implementing actions to address the risk (*e.g.*, 30 min)? If yes, when should the time start? End?

☒ Yes
☐ No

Comments: ERCOT believes a timing requirement is unnecessary, but, the requirement to implement actions should have very clear expectations so that pre-contingency load shedding does not occur unnecessarily. If the SDT chooses to add a timing requirement, the time period should start when the condition's effects are identified (e.g. when it is verified that post contingency cascading, instability, or uncontrolled separation exists) and end at the time that the risk of post contingency cascading, instability, and uncontrolled separation is no longer present. This timing requirement should not cover actual alleviation of the SOL exceedance, but rather a post contingency flow where there is still an SOL exceedance, yet the magnitude of the SOL exceedance has been reduced to a point at which the risk of cascading has been mitigated.

Question 22: Do you believe that this issue is already addressed in other Reliability Standards (*i.e.*, IRO-009 and EOP-011)? If not, should it be?

☐ Yes
☒ No

Comments: The Real-time operating state identified in R8 is not addressed in IRO-009 or EOP-011. It has been somewhat addressed in TOP-004-2 R2, however this requirement is going to be retired 4/1/17. ERCOT believes the relevant standards (TOP-001, IRO-009, and EOP-011) should be revised to address 1.) screening for instances where “the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation” and 2.) taking actions upon identification of these instances.

Question 23: If the proposed requirement is added, should a reciprocal requirement be added to require implementation of the method (*e.g.*, possibly a new TOP or IRO requirement)?

☒ Yes
☐ No

Comments: ERCOT believes that there should be corresponding IRO/TOP/EOP requirements to implement this “method” in R8 as part of this project. Failure to do so creates simply an administrative requirement with no performance obligation.

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology; **9.2.** Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.	added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	• FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its RC Area; and, each TOP that operates in its RC Area.

Question 24: Do you agree with the proposed revisions? If not, please explain why and provide any changes that you propose to the language.

☒ Yes

☐ No

Comments:

Comment Report

Project Name: Project 2015-09 Establish and Communicate System Operating Limits | FAC-014-3

Comment Period Start Date: 7/14/2016

Comment Period End Date: 8/12/2016

Associated Ballots:

There were 33 sets of responses, including comments from approximately 33 different people from approximately 30 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with that the Reliability Coordinator (RC) should have primary responsibility for establishing IROLs for its RC Area? If not, please provide your comments on the appropriate break down of responsibilities (between RC and TOP) in establishing IROLs.

2. The proposed revisions work together with the proposed revisions to the definition of SOL. The new requirement makes clear that the TOP will establish SOLs in accordance with the RC SOL Methodology. This means that the TOP will follow the RC Methodology to determine: applicable Facility Ratings for use in operations (see, proposed FAC-011-4 Requirement R2); applicable steady-state System voltage limits to be used in operations (see, proposed FAC-011-4 Requirement R3); and, the applicable stability limitations, if any, that are to be used in operations (see, proposed FAC-011-4 Requirement R4). Do you believe that it is clear that the TOP must establish SOLs in accordance with what is outlined in the RC Methodology?

3. TOP application of the RC Methodology will always result in identification of the appropriate Facility Ratings and steady-state System voltage limits, however, it may not always result in identification of stability limitations (this is *only if* there are no applicable limitations specific to the TOP). If there are appropriate stability limitations (identified as a result of implementing the RC method for determining the stability limitations in proposed FAC-011-4 Requirement R4), then the TOP will identify these SOLs. Do you believe this is clear from the language of the requirements (both in FAC-14-3 Requirement R2 combined with the proposed revisions to FAC-011)?

4. Do you believe that the RC should be responsible for establishing stability limitations used in operations where more than one TOP is impacted?

5. Do you agree that the RC should be the only entity responsible for providing other entities within its RC Area the established SOLs? If no, do you believe the entity that establishes the SOL (either the RC *or the TOP*) should be the entity that communicates the SOL to other entities? Please explain.

6. With regard to proposed Part 4.1: Do you believe that the language provides sufficient clarity regarding what is required for communicating updates to dynamically updated limits? If not, what language do you propose?

7. With regard to proposed Part 4.1: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the communications, or should the RC have flexibility in determining what is appropriate for its particular RC Area?

8. Do you agree with the information identified in Parts 5.1 through 5.4? Is there any additional information that the RC should provide regarding IROLs? Are there any additional entities that should be included in this requirement and receive the information from the RC?

9. In consideration of the FERC directive regarding communicating IROL information to the Transmission Owner, do you agree with this proposed new requirement? If not, please explain the basis for why you do not support the proposed requirement, and the alternative language you are proposing to address the issues raised in FERC Order No. 777.

10. Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the

information to the Transmission Owner and Generator Owner?

11. Do you agree that there is a reliability-related need for the RCs and TOPs to obtain the information from the Planning Assessment and Transfer Capability analysis for the purpose of identifying instability risks when establishing SOLs (and IROLs)? Are there other “studies” that are currently performed that should also be included in this communication requirement?

12. Are there additional “studies” or activities that planners should undertake (beyond those currently required in the current standards, including TPL-001-4 and FAC-013-2) to identify instability risks? If so, please describe.

13. With regard to Part 8.3: The SDT believes that the information listed in Part 8.3 is critical for RC and TOP awareness and understanding of the instability risks identified in the planning horizon and the listed mitigation measures employed to address those risks. Do you agree? If not, please explain why you believe it is not critical that the RC and TOP obtain this information from the planning entities?

14. Do you agree that this proposed requirement is appropriately placed in FAC-014, or do you believe the proposed requirement should be placed in another standard (*i.e.*, TPL-001-4 and FAC-013-2)?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Paul Mehlhaff	Sunflower Electric Power	1	SPP RE

						Corporation		
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Lower Colorado River Authority	Michael Shaw	1,5,6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Con Edison and ISO-NE	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power	NA - Not Applicable	NPCC

Council						Coordinating Council		
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE

					John Allen	City of Utilities of Springfield, MO	1,4	SPP RE
					Ron Losh	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Robert Hirchak	Cleco	1,3,5,6	SPP RE
Lower Colorado River Authority	Teresa Cantwell	1,5,6		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Teresa Cantwell	LCRA	1	Texas RE

1. Do you agree with that the Reliability Coordinator (RC) should have primary responsibility for establishing IROLs for its RC Area? If not, please provide your comments on the appropriate break down of responsibilities (between RC and TOP) in establishing IROLs.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy disagrees that the RC should solely be responsible for establishing IROLs. The TOP is and should be involved in the establishment of IROLs as well as the RC from a practical standpoint as well as a defense in depth standpoint. Multiple function having the ability or responsibility to communicate an IROL as needed provides an extra layer of defense to defend the reliability of the BES. We suggest the drafting team revise the language of R1 to provide for a collaboration between the RC and TOP in the establishment of IROL(s).	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
We should provide an option where the TOP may determine an IROL based on following the RC Methdology. We don't believe IROL's are the sole responsibility of the RC. There may be TOP's that have local problems that could have a wide area impact.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
We propose that the RC and the TOP both should have responsibilities for establishing IROLs, for their footprint, depending on the nature and impact of the limit. They will also be required to communicate and coordinate so that everyone is aware of the IROL's and that we	

operate to the most limiting condition. **Note: ERCOT and CAISO do not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
NOTE: The answers to questions 1 - 14 are from our City Light SMEs No comment for 1.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
We agree that the RC should have the primary responsibility for establishing IROLs, but believe that IROL should be established with input from the TOP and respecting TOP system operating limits.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. We appreciate the clarified responsibility for compliance. The RC should have as part of their process for establishment verification or validation of IROL's and the data from the TO or TOP's who are involved in the IROL.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
In some instances it may be relevant for the TOP to be involved in establishing an IROL.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
To be clear the PC and TP should coordinate with RCs when IROLS are identified in the planning horizon and the RC should coordinate with the PC	

and TP when IROLs are discovered in the operations horizon. The methodologies must be compatible so IROLs discovered in the long term look can be accommodated by the PC/TP process and be made known to the RC and vice-versa. With regards to TOPs, the TOPs should establish the IROLs within their Areas which should be confirmed with the RC review and the RC may have to develop IROLs that encompass more than one TOP asset. The TOP should establish IROLs per the RC methodology.

Likes 0	
Dislikes 0	

Response

2. The proposed revisions work together with the proposed revisions to the definition of SOL. The new requirement makes clear that the TOP will establish SOLs in accordance with the RC SOL Methodology. This means that the TOP will follow the RC Methodology to determine: applicable Facility Ratings for use in operations (see, proposed FAC-011-4 Requirement R2); applicable steady-state System voltage limits to be used in operations (see, proposed FAC-011-4 Requirement R3); and, the applicable stability limitations, if any, that are to be used in operations (see, proposed FAC-011-4 Requirement R4). Do you believe that it is clear that the TOP must establish SOLs in accordance with what is outlined in the RC Methodology?

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team. Additionally, we don't believe that every facility limit is an SOL nor is reaching a normal rating of a facility is an SOL exceedance. A different term is needed for this.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

No, the language is not entirely clear. It is not clear how IROLs fit in, nor does it address how the RC must be able to identify SOLs over a broader area than a TOP. It is an assumption that this will work with the revised SOL definition but “reliability limits” may be broader than a TOP can actually review and determine. Texas RE recommends SOLs and IROLs be identified in the planning horizon to be properly managed prior to the operations horizon.

The proposed language specifies the TOP will establish SOLs “consistent with” the RC’s methodology. Texas RE recommends using the phrase “in accordance with” to ensure the TOPs do what the RC Methodology says, rather than just perform actions that do not conflict with the RC methodology.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	No

Document Name	
Comment	
Because of the need to refer to FAC-011-4, FAC-011-4 and FAC-014-3 should be combined into one standard. Requirement R2 makes it clear that the Transmission Operator must establish IROLs, but as we commented on FAC-011-4, the owner of the equipment needs to be involved with the development of Facility Ratings. That will have to be considered in the applicability of FAC-014-3.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests clarification from the drafting team that this requirement does not infringe or conflict with FAC-008. As written, it could be interpreted that the RC would have some amount of leverage over an entity's own FAC-008 methodology. If that is the intent of the drafting team, we cannot agree with this approach. We do not believe the RC should have leverage or the ability to change/impact an entity's FAC-008 methodology.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
We disagree that the RC should be allowed to determine the Facility Ratings that are used in operations. Facility owners should decide what kind of equipment risk (i.e. loss of life) they are willing to take in operating their facilities. These assumptions are rolled in to the facility rating methodology. It is not appropriate to take this away from the facility owners.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	No
Document Name	
Comment	

It isn’t clear if the Reliability Coordinator or the TOP will identify the stability limitations described in FAC-011 R4 and therefore by requiring the TOP to establish SOLs in FAC-014 R2, it doesn’t ensure the TOP is identifying the stability limitations. This is especially true if the RC thinks the stability limitation is an SOL but the TOP thinks the stability limitation is an IROL, this may leave a gap where neither entity identifies the stability limitation.

Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee

Answer	Yes
Document Name	
Comment	

Note: ERCOT does not support the above comment.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

BPA agrees with R2, as it is a clear requirement and allows flexibility.

Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes

Document Name	
Comment	

Considering the structure and scope of the new standards, we suggest that the SDT consider merging FAC-011 and FAC-014 in a single standard. If the standards are not merged, the purpose of FAC-014-2 should be modified to reflect the title of the standards and its requirements. E.g. To ensure SOLs are established and communicated to the relevant entities.

Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	Yes
Document Name	
Comment	

The SDT might consider including the preface to question 2 in a technical guidelines section of FAC-011 to clarify expectations.

Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	
Comment	

1. The requirement is clear that the TOP must establish SOL's in accordance with what is outlined in the RC Methodology. One item to consider is that flexibility must be allowed for the TOP to place stricter limitation where local sensitivities may require individual differences with the RC's Methodology.

Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Very clear.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. TOP application of the RC Methodology will always result in identification of the appropriate Facility Ratings and steady-state System voltage limits, however, it may not always result in identification of stability limitations (this is *only if* there are no applicable limitations specific to the TOP). If there are appropriate stability limitations (identified as a result of implementing the RC method for determining the stability limitations in proposed FAC-011-4 Requirement R4), then the TOP will identify these SOLs. Do you believe this is clear from the language of the requirements (both in FAC-14-3 Requirement R2 combined with the proposed revisions to FAC-011)?

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

It isn't clear if the Reliability Coordinator or the TOP will identify the stability limitations described in FAC-011 R4 and therefore by requiring the TOP to establish SOLs in FAC-014 R2, it doesn't ensure the TOP is identifying the stability limitations. This is especially true if the RC thinks the stability limitation is an SOL but the TOP thinks the stability limitation is an IROL, this may leave a gap where neither entity identifies the stability limitation.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

We support SPP RTO comments.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	No
Document Name	

Comment

The statement that TOP application of the RC Methodology will always result in identification of the appropriate Facility Ratings and steady-state System voltage limits is incorrect. It assumes that the RC Methodology is complete and comprehensive. Qualifying all results will be accurate based upon on the use of RC Methodology may not always be true. It is clear that if the RC Methodology is used that the TOP is in

compliance, but not that the results will always be 100% accurate or complete.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
No, we do not think the expectations are clear based on the language proposed. We believe that the proposed language makes the issue somewhat confusing. The requirement should more simply outline responsibilities and expectations. An entity is expected to operate within its facility limits, if stability limitations are present, this would rise to the categorization level of an SOL. From this point, the determination of an IROL may be ascertained.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Because of the need to refer to FAC-011-4, FAC-011-4 and FAC-014-3 should be combined into standard.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It is not clear, based on the definition of SOL exceedance whether an entity is required	

to have online (vs offline) stability analysis capabilities. Also, the way the definition is worded could also lead an entity to interpret that they HAVE to identify stability limitations (stress till it breaks).	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
It is not clear, based on the definition of SOL exceedance whether an entity is required to have online (vs offline) stability analysis capabilities. Also, the way the definition is worded could also lead an entity to interpret that they HAVE to identify stability limitations (stress till it breaks).	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. It is not clear, based on the definition of SOL exceedance whether an entity is required to have online (vs offline) stability analysis capabilities. Also, the way the definition is worded could also lead an entity to interpret that they HAVE to identify stability limitations (stress till it breaks?).	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

“Yes” I believe this requirement, in conjunction with the new definition of SOL, make it clear that a TOP must include transient stability limits and voltage stability limits when determining SOL’s.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

FAC-011-4 R4 requires the RC to include stability in its SOL methodology, so TOP implementation of the RC methodology should pick up stability SOLs.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

We believe the intent to calculate SOLs that are restricted by stability limitations are clear from the language of the requirements (both in

FAC-14-3 Requirement R2 combined with the proposed revisions to FAC-011).

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	Yes
Document Name	

Comment

The SDT might consider including the preface to question 3 in a technical guidelines section of FAC-011 to clarify expectations.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	

Comment

It would be much clearer if the requirements from both standards were merged in a single standard.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you believe that the RC should be responsible for establishing stability limitations used in operations where more than one TOP is impacted?

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the RC should not be responsible for establishing stability limitations, except when a limit has been established as an IROL.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
No, we do not believe the RC should be responsible for establishing stability limitations even when more than one TOP is impacted. We do not believe that all RCs throughout all of the Interconnections regularly perform stability studies, or are even set up to perform these studies at all. We believe that coordination should take place between impacted TOPs prior to being relayed to the RC.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
The stability limitations should be jointly developed by the impacted Transmission Owners. The RC may not have the expertise to develop stability limitations for all areas of its system.	
Likes 0	
Dislikes 0	

Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. The RC SOL Methodology will include instability criteria, as such it would make sense that the RC review all stability limitation determined by the TOP to eliminate all stability limitations from being possible IROL's instead of just those involving more than one TOP.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
In the planning horizon, the PC should also be responsible for establishing stability limitations used in operations where more than one TOP is impacted.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Yes, we agree, but that's already achieved by the RC developing IROLs, which can be restricted by stability limitations.

As such, we do not believe R3 in FAC-014-3 is needed given that the RC is required to develop IROLs and the TOP for SOLs combined with the proposed revised definition of SOL (with our suggested wording change indicated in the FAC-011 Comment Form), whose determination must meet acceptable BES performance with respect to Facility rating, System voltage limits, and stability limitations. System limitations are a measure or a restriction which needs to be respected in assessing BES performance, but itself not an SOL or IROL. However, by virtue of developing SOLs and IROLs that simultaneously satisfy all three restrictions (Facility Rating, System voltage limits and stability limitations), the BES is deemed to be reliable if operated within these limits.

While we concur with the SDT that "not all stability limitations are automatically IROLs" and that "there may be instances of local, contained instability that are not appropriately designated an IROL", SOLs that have local impact only are also developed respecting stability limitations. With the TOP establishing stability limitation SOLs and the RC establishing stability limitation IROLs, we do not see a reliability gap and are unable to identify what other stability limitations may exist that could impact more than one TOP in an RC Area that are not already covered by IROLs.

In brief, we believe the determination of SOLs and IROLs should be governed by the follow basic principles:

1. **The RC develops the SOL and IROL calculation methodologies considering the restrictions imposed by/performance criteria for Facility Rating, System voltage limits and stability limitations, along with the scope of single and multiple contingencies to be observed and the acceptable BES performance.**
2. **The RC develop the method and criteria for establishing IROLs;**
3. **The TOP calculates SOLs, which have local area impact;**
4. **The RC calculates IROLs, which have impacts on more than one TOP areas.**

We suggest the SDT to develop the FAC standards based on the above basic principles as opposed to trying to find holes in them and propose requirements that are duplicative or unnecessary. (please see our argument that stability limitations are not IROLs in the FAC-011 Comment Form).

Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
The RC should work with the TOP in a collaborative and coordinated process to address/establish stability limits and particularly when more than one TOP is impacted. The RC may also need to work with another RC when stability issues are identified on the seams.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS believes the RC should be responsible for establishing stability limitations used in operations where more than one TOP is impacted, unless another established agreement is in place between the affected TOPs which clearly defines the party responsible for establishing stability limitations.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
There seems to be a gap in the requirements for instances where there is a stability limit between two TOPs with different RCs.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
We agree with and fully support the fundamental concept that not all stability limitations are automatically "IROLs."	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes. If a TOP establishes a lower SOL for any reason, the neighboring TOP should be forced to use the most restrictive SOL. The RC is the appropriate entity to study and enforce these situations. It may be helpful to clarify that TOP studies will feed into this process, rather than being the sole responsibility of the RC (if this is so).	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	
Document Name	
Comment	
Peak supports this concept that RCs should collaborate with TOPs in the establishment of stability limitations where more than one TOP is impacted; however, a potential unintended negative consequence of the language as proposed is that TOP-to-TOP coordination, collaboration, and communication could be diminished. TOPs that might have otherwise been working collaboratively with neighboring entities might use the language in proposed R3 as a justification for “lowering the bar”, potentially creating a TOP mindset that says, “It’s not my responsibility – it’s the RC’s responsibility – so, I no longer need to work with my TOP neighbor in addressing these stability limitations.” The language should not serve as an enabler for lowering reliability the bar.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree that the RC should be the only entity responsible for providing other entities within its RC Area the established SOLs? If no, do you believe the entity that establishes the SOL (either the RC *or the TOP*) should be the entity that communicates the SOL to other entities? Please explain.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
No. If TOPs are individually responsible for determining their SOL's, then they should be responsible for communicating them when they change. The RC should be responsible for determining and communicating IROL's and SOLs that impact more than one TOP including the SOLs of all the tie-lines between TOPs.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
The RC should be the primary entity responsible for providing other entities with the established SOLs, but TOPs should exchange SOLs with each other if requested or the need arises.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
No, we do not agree that the RC should be the only entity responsible for providing other entities within the RC Area the established SOLs. It is not clear to us why relaying this information should lie solely with the RC. We believe the TOP should be allowed to relay this information to let other entities know if they will be impacted by the SOL. We understand that even if a TOP were to communicate this information with other impacted entities, the RC would still need to be notified as well. To allow for flexibility of multiple avenues of communication as well as allowing for the RC to be notified, we	

suggest the drafting team consider the following:

" Each Reliability Coordinator shall ensure that SOLs in its RC Area are provided to adjacent Reliability Coordinators within an Interconnection…"

The above language and the use of the term "ensure" makes certain that the information is relayed appropriately, but allows for flexibility in who shall relay said information.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We believe the entities that develop the SOLs (the TOPs) should be responsible for providing other entities within its RC Area the established SOLs. This is in line with the RC developing IROLs and TOP developing SOLs.

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA's concern that this interpretation would hamper TOP-to-TOP communication and timing, e.g. Seasonal Studies usually have a few old facility ratings that are identified and this information is required well before the RC needs it.

Also it conflicts with TOP-003-3 R3 & R5 and could be duplicative of IRO-010-2.

WAPA does believe that the RC should be the "clearing house" for SOL information (among other things) come Day 0-1.

Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
We believe the entities that develop the SOLs (the TOPs) should be responsible for providing other entities within its RC Area the established SOLs. This is in line with the RC developing IROLs and TOP developing SOLs	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
The standard should (and does) establish that the RC is responsible for communicating all the SOL values. However the wording in FAC 14 R4 is unclear. Which parties does the RC provide data automatically? Which parties do they only have to provide data to upon request? Why is the TSP only able to get SOLs for just it's TOP?	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
We believe that any SOL developed by the TOP should be reviewed by the RC before communicating to other entities.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	
Comment	

The RC should be responsible but may not necessarily be the entity that establishes the SOL. TOPs may establish SOLs but the RC has the responsibility to review, approve, and disseminate the SOL..

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	
Comment	

The RC should also provide SOLs to RCs outside of its interconnection.

Texas RE is concerned with the use of the phrase “reliability-related need” as it is subjective and will be difficult to determine. Texas RE sees no harm in removing this phrase so the RC must provide the information when asked by Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

Likes 0	
Dislikes 0	
Response	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It will make the communication more consistent in the long run if all entities know that the RC will be the one communicating the information. However, we request that in order to avoid making this requirement an administrative nightmare, the requirement should be restated to require the RC to make changes to SOLs ‘available’ rather than requiring them to demonstrate communication (which also requires proof of receipt). The unintended consequence of the requirement as proposed is that the RC now has to maintain and validate constantly the list of entities who need this information. TOPs, other RC's, and other entities who need the data, also share in the obligation to make sure they get it. Putting it solely on the RC to communicate it, removes any obligation from other entities to make sure they have the SOL information they need. Additional Rationale may be needed to further explain this.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

It will make the communication more consistent in the long run if all entities know that the RC will be the one communicating the information.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Yes, but we believe that the requirement should be modified to say "Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area."

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment	
1. Placing this requirement on the RC level would drive consistencies in SOL's across the Interconnection and provide better coordination for TOP's located near RC area borders. It would also improve the Data communication requirements established within the IRO-010 and TOP-003 requirements. 2. Editorial comment: In the 'Explanation of Proposed Revision' column, change "TC" to RC.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Peak supports the concept of the RC serving as the data source for SOLs (per the revised SOL definition). This is a cleaner and simpler model than each SOL establisher communicating SOLs with other entities that need them.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Yes, the RC should have this responsibility. However, we consider that the standard gives a simplified picture of the complexity of communicating an SOL. For example, an SOL is not a static value : it can depend on many factors and evolve through time. We store (and calculate) SOLs in a complex EMS application. The information can be difficult to extract and even once communicated, difficult to interpret by the receiving entity. Some guidance around expectations for this communicated SOL should be circulated for comment in a future draft. The above problem is compounded if, as the requirement implies, an entity will receive all established SOLs. Since an entity is probably only interested in the SOLs that can affect it and does not wish to be submerged by all existing SOLs in the RC area and communicating all SOLs to all entities distributes sensitive information more broadly than necessary to support reliability, we propose limiting the required distribution of SOLs, perhaps "Each RC shall provide SOLs for its RC Area **that may impact the other entity** (…)" or alternatively "Each RC shall provide SOLs for its RC Area to entities **that have a reliability-related need** (…)"	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the intent of R4. However, we feel it is still important for the TOPs to be required to communicate, coordinate and share its SOLs to neighboring or impacted TOPs.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

6. With regard to proposed Part 4.1: Do you believe that the language provides sufficient clarity regarding what is required for communicating updates to dynamically updated limits? If not, what language do you propose?

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
The 4.1 sub-requirement seems redundant and unnecessary. The SDT should consider rewording R4 in a single part. Other suggestions: "Each RC shall provide any updates to the SOL values established dynamically or offline (…)" Since the SOLs provided in R4.1 may include IROLs, is it possible that the corresponding Tv may also have been updated. Thus: "Each RC shall provide any updates to the SOL values and corresponding Tv if applicable (…)"	
Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Though Peak agrees with the concept, it is difficult to glean the proper understanding of R4.1 without the explanation provided. Peak suggest crafting language that more clearly conveys the expectation. The SDT should also consider clarifying these expectations in a technical guidelines section of FAC-014.	
Likes 0	

Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	

Part 4.1 needs to be revised if R4 is changed such that the TOP is responsible for communicating SOLs to others. Wrt what is required for communicating updates to dynamically updated limits, we are unable to answer that part since Part 4.1 makes references to R1 and R3 is, neither of which have anything to do with SOLs.

Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. With the way Requirement R4 is written, it is not clear if a dynamically determined Facility Rating (that is telemetered in real-time for example) is required to be communicated (in Real-time?) to the TP and PC also. There may be value in requiring that information be provided to the TP and PC (such as the range of dynamically determined values experienced); it is not clear what needs to be provided.

2. We suggest adding some tie to the IRO-010 and TOP-003 Standards such as “4.1 The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format as stated in the Reliability Data Specifications established in IRO-010 and TOP-003.”

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

With the way R4 is written, it is not clear if a dynamically determined Facility Rating (that is telemetered in real-time for example) is required to be communicated (in real time?) to the TP and PC also. There may be value in requiring that information to be provided to the TP and PC (such as the range of dynamically determined values experienced), however it is not clear what needs to be provided.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] With the way R4 is written, it is not clear if a dynamically determined Facility Rating (that is telemetered in real-time for example) change is required to be communicated (in real time?) to the TP and PC also. There may be value in requiring that information to be provided to the TP and PC (such as the range of dynamically determined values experienced), however it is not clear what needs to be provided.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Part 4.1 needs to be revised if R4 is changed such that the TOP is responsible for communicating SOLs to others. Wrt what is required for communicating updates to dynamically updated limits, we are unable to answer that part since Part 4.1 makes references to R1 and R3 is, neither of which have anything to do with SOLs.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No

Document Name	

Comment

Because of the importance of operating to SOLs, the time to communicate updates needs to be specified. Propose the following wording to Part 4.1:

The Reliability Coordinators shall provide any updates to the SOL values that affect System Operating Limits established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinator Area within 15 (fifteen) minutes of being calculated.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

No, we do not believe the language provides sufficient clarity regarding what is required for communicating updates to dynamically updated limits. It is unclear what the drafting team means by dynamically updated limits. The term dynamically updated limits does not appear in the requirement, and it is not very clear on what this alludes to. Also, we are unsure of the necessity of Part 4.1. We believe that this may already be accomplished via the IRO and TOP standards.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

Support SPP RTO Comments.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
When SOLs are communicated, it must also be communicated how those SOLs are to be used, e.g. time limits associated with each rating, temperatures associated with each rating, whether ratings can be interpolated between temperatures, etc..	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
No. Dynamically determined facility ratings are not mentioned at all in the language, so I'm not sure how it provides any clarity. Entities that use dynamically determined ratings should be required to effectively communicate those ratings in real time to the RC and all effected entities. Those entities should be required to fully implement an operating agreement specifying the use of Dynamic ratings with adjacent TOPs before they can be used in the Planning Horizon or Operating Horizon.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
Why does Part FAC 14 part 4.1 not cover TOP ratings provided in FAC 14 R7? Shouldn't FAC 14 R7 include language similar to FAC 14 Part 4.1 regarding regular updates, format, and periodicity of updates? This does not preclude the TOP from providing the information to someone, but the standard responsibility should be on the RC who gathers all the SOLs from all the TOPs.	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
TOP-to-TOP communications are addressed in TOP-003-3 R3 & R5	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned there is no guidance on how “impacted” TOPs are determined.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
The question is not clear. What are dynamically updated limits?	
Likes 0	
Dislikes 0	
Response	

7. With regard to proposed Part 4.1: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the communications, or should the RC have flexibility in determining what is appropriate for its particular RC Area?

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
The RC should have the flexiblity.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
The RC should have flexibility in determining what is appropriate for its particular RC Area. The time frame of the communications could be outlined in the RC SOL methodology. RCs may just provide TOPs with access to a RC area ratings database instead of providing communications, it may be worth looking into if this type of communication would be acceptable or if notification of ratings changes is what the standard drafting team is looking for. For large RC areas with a large number of TOPs these notifications could become numerous for the TOPs and contain information they don't care about.	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
RC should have flexibility.	
Likes 0	

Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The statement of “mutually agreeable periodicity and format” allows flexibility, but also ensures that TOPs receive the needed information when needed.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
Support SPP RTO Comments.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
No, we do not believe that a specific timeframe is necessary for when the RC must provide these communications. We agree that the RC should be afforded the flexibility of determining what is appropriate for its particular RC Area.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
The RC and the mutually agreeable party should retain the flexibility around this exchange. If the concept of “minimum acceptable time” around such communications were to be included, it would be best to have that as a requirement that should be established and/or defined within, or ancillary to, the RC’s Methodology.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] We agree that the RC should communicate updates as soon as possible in order to facilitate accurate OPAs and RTAs; however the nature of the updates may not always be time sensitive. For example an update to an SOL that may be effective at a future date. It may be difficult to set a minimum acceptable time in the standard to cover all the various types of updates that may be received. Including a timeframe may result in a requirement that is too prescriptive and would result in requiring a specific means of exchanging information in order to meet the requirement. The RC could describe the method and timeframe within its data exchange documents in IRO-010.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We agree that the RC should communicate updates as soon as possible in order to facilitate accurate OPAs and RTAs; however the nature of the updates may not always be time sensitive. For example an update to an SOL that may be effective at a future date. It may be difficult to set a minimum acceptable time in the standard to cover all the various types of updates that may be received. Including a timeframe may result in a requirement that is too prescriptive and would result in requiring a specific means of exchanging information in order to meet the requirement. The RC could describe the	

method and timeframe within its data exchange documents in IRO-010.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. We agree that the RC should communicate updates as soon as possible in order to facilitate accurate OPAs and RTAs; however the nature of the updates may not always be time sensitive. For example, an update to an SOL that may be effective at a future date. It may be difficult to set a minimum acceptable time in the standard to cover all the various types of updates that may be received.

2. Including a timeframe may result in a requirement that is too prescriptive and would result in requiring a specific means of exchanging information in order to meet the requirement. The RC could describe the method and timeframe within its data exchange documents in IRO-010.

3. If tied back to the IRO-010 and TOP-003 the timeframe should be the mutually agreed to timeframes between the different functional entities.

Likes 0	
Dislikes 0	

Response

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

RC should have flexibility in coordination with TOPs in determining what is appropriate for its particular RC area.

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance

Answer	No
Document Name	

Comment	
RC should have flexibility in determining what timeframe is appropriate for its area.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Peak believes a timeframe specification is not necessary for reliability.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the RC should have flexibility in determining what is appropriate for its RC area.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

RC should have flexibility in determining what timeframe is appropriate for its area.

Likes 0	
Dislikes 0	

Response
Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment
We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response
sean erickson - Western Area Power Administration - 1,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment
RC should have the flexibility to provide more often updates as necessary but there should be a minimum of one update every year.

Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
There should be a hard limit for providing the communication to provide for reliable operation of the BPS. One suggested timeframe would be 30 minutes. This would provide the RC ample time to disseminate the communication and ensure it has been received.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
See the response to Question 6.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
R4 needs to be revised if R3 is changed such that the TOP is responsible for communicating SOLs to others. Wrt time frame, there should be a specific time for such communications since this information is needed by all parties prior to implementing any new or revised SOLs.	
Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Any time a stability limit is identified by a TOP, specifically when the limitation impacts more than one TOP, the RC should immediately notify all impacted TOPs.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
“in a mutually agreeable periodicity and format.” seems appropriate to consider the particular needs of each TOP as inputs to define the timeframe.	
Likes 0	
Dislikes 0	
Response	

Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
Flexibility seems appropriate.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	
Document Name	
Comment	

We support allowing the RC the flexibility and discretion to determine what is appropriate for its RC Area.	
Likes 0	
Dislikes 0	
Response	

8. Do you agree with the information identified in Parts 5.1 through 5.4? Is there any additional information that the RC should provide regarding IROLs? Are there any additional entities that should be included in this requirement and receive the information from the RC?

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
I am concerned with the word “critical” in 5.1 – is “pertinent” more appropriate? Also, items 5.1-5.4 should be the minimum and this should not preclude providing additional information about the IROL that the RC and affected entities feel is necessary.	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
I am concerned with the word “critical” in 5.1 – is “pertinent” more appropriate? Also, items 5.1-5.4 should be the minimum and this should not preclude providing additional information about the IROL that the RC and affected entities feel is necessary.	
Likes 0	
Dislikes 0	

Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
☐ Q8.1 Yes, PJM agrees with the information provided in Parts 5.1 – 5.4. ☐ Q8.2 No, PJM doesn't feel the Standard needs a further requirement around IROL derivation. ☐ Q8.3 Yes, impacted neighboring TOPs are other potential recipients.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
The only information that needs to be provided are Part 5.2 (IROL and IROL Tv), and Part 5.4 (IROL type). Parts 5.1 and 5.3 only need to be known internally to the RC.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
The term “Facilities that are critical to derivation of IROL” is not clear. Does it refer to substation as a whole or the elements in the substations? It would be more appropriate to use the word “elements” since IROL is related to specific contingency causing problems on specific elements.	
Likes 0	

Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Information similar to that provided in Parts 5.1 to 5.4 should also be specified in Requirement R4 for communicating SOLs/ (i.e. those entities that need to know the SOL should also be provided the related information, or else they don't need the SOLs to begin with).	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that the information in Parts 5.1 through 5.4 is adequate. The RC should communicate its IROLs to BAs in its RC footprint.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
In 5.2, the term "value" does not seem appropriate. The value of the IROL is only relevant for a specific system condition. The IROL calculation method that includes the IROL values for various System conditions should be shared when[GM1] appropriate. We note that R5 and R4 are highly redundant in structure. Since we argue for a rewrite of R4 in the previous questions, we suggest that R4 and R5 could be combined, and a sub requirement of R4 drafted to address SOLs that are IROLs have an additional series of content requirements as per the actual subrequirements of 5.	

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
R5 is adequate as written.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. We agree, and no additional information should be necessary.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The list appears to be a subset of the entire story. The Assumption is 5.1 will contain the necessary details, e.g. Un-Seasonable load, shoulder season	

lows, prior outage(s), known issue, etc to allow the effected neighboring entities a full understanding.

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

Texas RE suggests adding a Requirement to FAC-014-3 to address operating states where the next contingency has the potential to cause System instability, Cascading outages or uncontrolled separation.

Note that the IROL provision to the PC/TP is very appropriate and should be in-line with a methodology to identify IROLS. Part 5.4 includes “angular stability” which may or may not be covered by the newly proposed SOL definition. The SOL definition is too wide and does not provide the proper guidance expected with a definition.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment	
Information similar to that provided in Parts 5.1 to 5.4 should also be specified in Requirement R4 for communicating SOLs/ (i.e. those entities that need to know the SOL should also be provided the related information, or else they don't need the SOLs to begin with).	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Yes, Duke Energy agrees with the information identified in Parts 5.1 through 5.4. However, we suggest adding language stating that the sharing of this information is required if neighboring RC Areas are impacted, and remove the language regarding the demonstration of a reliability related need.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The RC should also include any mitigation identified to resolve the IROL, and the RC should provide the information to entities with actions in the IROL, such as GOPs with actions.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment	
No additional entities need to be included.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Information in Parts 5.1 to 5.4 is adequate for BES reliability. No additional information or entities should be included.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
FAC 14 R5 is unclear. Who does the RC have to provide the data to by default? Who does it have to provide data to upon request? Also shouldn't Transmission Service Providers be included as entities that can request the data so they aren't limited to just their TOP area?	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	

9. In consideration of the FERC directive regarding communicating IROL information to the Transmission Owner, do you agree with this proposed new requirement? If not, please explain the basis for why you do not support the proposed requirement, and the alternative language you are proposing to address the issues raised in FERC Order No. 777.

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
FAC 14 R6 should require the RC to respond to a query from a Transmission Owner to either define the facilities or specify that they do not have any facilities that are critical to the derivation of the IROL.	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS believes it would be more appropriate to use the word “elements” since IROL is related to specific contingency causing problems on specific elements.	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
No, we believe that information should be supplied to any adjacent TOs and GOs. The requirement should be modified to say “Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners.”	
Likes 0	

Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Yes, we agree that the RC is best suited to provide this IROL information to TOs and GOs in this instance. As stated earlier, while the RC may be best suited in this instance, we do believe that the TOP is capable of, and should be included in the establishment and communication of IROLs in some instances as well.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	Yes
Document Name	

Comment

Suggest Requirement R6 to read:

R6. Each Reliability Coordinator with an established IROL shall provide to the Transmission Owners and Generation Owners identification of the Facilities they own that are critical to the derivation of that IROL.

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. We agree, and have no additional comments.	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
I would also add an RC requirement to positively state that no TO or GO facilities were pertinent to the derivation of an IROL – otherwise, a missed notification could be construed as “no facilities”. Also, prefer “pertinent” to “critical”.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
The requirement needs to be reworded in a single part to reduce confusion and facilitate compliance.	

Since the need for IROL information is related to FAC-003, the information given to the TOs and GOs should be limited to what they need to apply FAC-003 and using the same language as FAC-003 to avoid any confusion. Thus we propose: "R6.1 Identification of the **lines** that are owned by that entity, which **are an element of an** IROL."	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team. Additionally, we don't believe that every facility limit is an SOL nor is reaching a normal rating of a facility is an SOL exceedance. A different term is needed for this.	
Likes 0	
Dislikes 0	
Response	

10. Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the information to the Transmission Owner and Generator Owner?

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the RC should have flexibility in determining what is appropriate for its RC area.	
Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Peak believes a timeframe specification is not necessary for reliability.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
RC, TO and GO should coordinate with each other through the RC to determine appropriate timeframe.	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe it would be difficult to come up with a timeframe that would not result in an administrative requirement. TO and GO tasks are not typically related to Real-time reliability, so establishing a time limit is not related to preserving reliability. It's simply facilitating compliance. 2. TOP's and then GOP's should receive the information necessary for Real-time operation in a timeframe necessary to protect BES Reliability. The TO and GO would need the information for future Planning requirements and therefore we believe the RC should NOT delay in notifying TOs and GOs of their ownership of those facilities since they have supportive reliability related tasks (FAC-003, CIP, etc.) to perform. Any time limit should be based on effectively facilitating those activities.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
It would be difficult to come up with a time that would not just result in an administrative requirement. TO and GO tasks are not typically related to real-time reliability so establishing a time limit is not related to preserving reliability, but facilitating compliance. However the RC should not delay in notifying them of their ownership of those facilities since they have supportive tasks (FAC-003, CIP, etc) for reliability that need to be undertaken. Any time limit should be based on appropriately facilitating those activities.	
Likes 0	

Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It would be difficult to come up with a time that would not just result in an administrative requirement.   TO and GO tasks are not typically related to real-time reliability so establishing a time limit is not related to preserving reliability, but facilitating compliance. However the RC should not delay in notifying them of their ownership of those facilities since they have supportive tasks (FAC-003, CIP, etc) for reliability that need to be undertaken. Any time limit should be based on appropriately facilitating those activities.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	No
Document Name	

Comment

If the concept of "minimum acceptable time" around such communications were to be included, it would be best to have that as a requirement that should be established and/or defined within, or ancillary to, the RC's Methodology.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

No, we do not believe that a specific timeframe should be required for the RC to provide this information to a TO or GO.

Likes 0	

Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
Support SPP RTO Comments.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
The time criticality depends upon the type of scenario. For example, if the real- time assessment shows that the next contingency is creating an IROL, it is important the TOP and GOP be identified and notified ASAP. The TO, GO, should also be notified in due course.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
The RC should have flexibility in determining what is appropriate for its particular RC Area. The time frame of the communications could be outlined in the RC SOL methodology.	
Likes 0	
Dislikes 0	

Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	

Comment	
Yes, we believe such communication needs to occur some days prior to the new or revised IROLs are implemented. **Note: ERCOT does not support the above comment.**	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Texas RE recommends setting a time limit for providing the IROL information to the Transmission Owners and Generation Owners within its RC Area since certain activities, such as CIP-014-2 activities, may have to occur after the provision. Texas RE recommends IROLs be established in the planning horizon so TOs and GOs would be notified prior to the IROL becoming operational. The proposed revisions to the SOL definition no longer requires IROLs to be established in the planning horizon.

Texas RE recommends the SDT consider the following:

- It appears the applicability section of FAC-003-4 intends that IROLs will be identified in the planning horizon, since section 4.3.1.2 uses the language "Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator."
- If the PC is no longer required to have an SOL methodology, it is unlikely that the PC will identify IROLs. Does this mean that elements of an IROL are no longer applicable in FAC-003-4 since they were not identified by the PC?
- If the purpose of this requirement is to make TOs and GOs aware of compliance obligations related to Facilities identified as part of an IROL (FAC-003-4), how will this be handled for IROLs that are established in real-time due to system configuration, but retired after outages are returned to service?
- How will TOs and GOs be compliant with FAC-003-4 if they are not aware their Facility is an element of an IROL until the end of the calendar year?
- The Applicability section 4.1.1.3 of CIP-014 includes Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. If the PC and TP are no longer required to identify IROLs, does this mean that these Facilities will not be identified as applicable until a real-time IROL is identified? If so, the implementation of physical security measures may not be completed for years after the IROL is identified.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Yes, we believe such communication needs to occur some days prior to the new or revised IROLs are implemented.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	Yes
Document Name	

Comment

The Transmission Owners and Generation Owners should be notified within 15 minutes after their facilities are determined to be critical to the derivation of the IROL.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	

Comment

As stated in Q7, a suggested timeframe is 30 minutes.

Likes 0	
Dislikes 0	

Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
A timeline should be provided to ensure the TOs and GOs receive changes in a timely manner.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
FAC 14 R6 should establish a minimum time for an RC to respond to a request from a transmission owner that they do or do not have any facilities that are critical to the derivation of the IROL.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

11. Do you agree that there is a reliability-related need for the RCs and TOPs to obtain the information from the Planning Assessment and Transfer Capability analysis for the purpose of identifying instability risks when establishing SOLs (and IROLs)? Are there other "studies" that are currently performed that should also be included in this communication requirement?

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

We subscribe to the MRO NSRF's comment that is provided below:

There is not an operating horizon reliability need for RCs and TOPs to have planning horizon Planning Assessments and Transfer Capability analyses because any future system performance deficiencies will be mitigated by Corrective Action Plans before the planning horizon timeframe becomes the operating horizon timeframe. In addition, planning horizon studies have some fundamental differences from operating horizon studies that reduce the worth of planning horizon finding for operating horizon purposes. Planning horizon studies are chiefly performed for firm Transmission Service and firm forecasted Load conditions. Operating horizon studies are performed for non-firm Transmission Service and non-firm, more accurately forecasted Load conditions. Operating horizon studies generally simulate only generator, line and transformer N-1 event contingencies, but planning horizon studies simulate a wider spectrum of planning event contingences (P1-P7), which include more severe, but less probable events. If there is a reliability-related need to know the expected system performance in the operating horizon for firm Transmission Service and Load operating conditions or for less probable planning event contingencies then RCs and TOPs can perform these types of simulations themselves as needed.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

Planning Assessment results are available to the RC from the PC. However, most of this information will not be applicable in the Operating Horizon, and we should not overburden the RC with voluminous results of non-applicable information. Planning Assessment results are dependent on specific generation dispatch, system configuration, load level, location and type of fault, clearing times (including failure of some equipment to clear), etc. In our opinion, it is doubtful that this planning information would be used to develop SOLs and IROLs.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	
Comment	

Support SPP RTO Comments.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	

We question the placement of this requirement which requires a Planning Coordinator or Transmission Planner to act. We think that this requirement would be more suitable in the TPL-001-4 and FAC-013-2 standards where the requirements for distribution of the associated assessment results already exist. A compliance “trap” may be created by placing a requirement to communicate the results in another standard not directly associated with performance of the assessment results being communicated. Note that these two standards already require distribution of the assessments, when requested, to functional entities with a reliability need. While we agree that information from a Planning Assessment or Transfer Capability Assessment may be of some overall value to RC’s, we fail to clearly understand how this information will be of direct value to the RC in the near-term operation of the system. For example, from an operational standpoint, a RC or TOP is dealing with the system based on whatever outages Generation and Transmission exist or the load levels they are at currently. Some useful information may be gleaned from the results of a TPL stability assessment, but this won’t help directly determine what operators are facing in the day ahead or month ahead from a stability standpoint.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	

While this may be a good practice and the information may be helpful for the RC and TOP to be aware of the stability risks/phenomena, this does not rise up to a standard level since the RCs and TOPs should already have some knowledge or will conduct some sensitivity testing to gauge the stability performance to begin with. We suggest to remove it.

Likes 0	
Dislikes 0	

Response

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] It is not clear which Transfer Capability assessment the requirement is referring to? Is it the one in FAC-013? Not all Transfer Capability assessments are stability based. Also, we would like further explanation from the team regarding how and what planning assessment information should be communicated from other requirements such as FAC-013, TPL-001, and IRO-017. Guidance from the team that it interprets the information to come from XYZ would be helpful.

We request that the team provide clarity that information needed from the planning assessments related to stability should be limited to only those applicable to the RC. For example, the RC should have little interest in an identified stability issue in the long term (10 years) that may have projects constructed to resolve by then.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

It is not clear which Transfer Capability assessment the requirement is referring to? Is it the one in FAC-013? Not all Transfer Capability assessments are stability based.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment	
1. It is not clear which Transfer Capability assessment the requirement is referring to? Is it the one in FAC-013? Not all Transfer Capability assessments are stability based. 2. There is not an operating horizon reliability need for RCs and TOPs to have planning horizon Planning Assessments and Transfer Capability analyses because any future system performance deficiencies will be mitigated by Corrective Action Plans before the planning horizon timeframe becomes the operating horizon timeframe. If there is a reliability-related need to know the expected system performance in the operating horizon for firm Transmission Service and Load operating conditions or for less probable planning event contingencies, then RCs and TOPs can perform these types of simulations themselves as needed.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
Concern: We infer that including “Transfer Capability assessments” is related to FAC-013 Requirements. The FAC-013 Standard is only applicable to PCs, not TPs. Also, FAC-013 does not require stability analysis for Transfer Capability assessment. In consideration of FAC-013, proposed FAC-014-3 R8 should not imply the necessity for stability analysis for Transfer Capability assessment. **Suggestion**: Delete “and Transfer Capability assessment” from proposed FAC-014-3 R8 language.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Was the intent to capture the study results under TPL 001-4 and FAC 13? Or to capture information from any type of study performed by the TP and PA that might be interpreted to be a Planning Assessment or Transfer Capability assessment?	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes. Agree with the need. The SOLs established in the near term transmission planning horizon should also be included. Do not know of any other studies.	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
See Seminole's response to question 14 below. CIP-014 requires the TO to perform a transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. This analysis is typically performed by the TP or PC; however, there is no requirement in CIP-014 as drafted, that requires the TO to notify the RC of such stations, which may be information that the RC should be aware of to understand the sensitivity/criticality of the identified stations.	

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

The Transfer Capability analysis performed by the Planning Coordinator does not necessarily include stability analysis. This could lead to a gap whereas stability risks associated with transfers or loop-flows across a system are not being identified and communicated to the RCs and TOPs.

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

The RC should be receiving the Planning Assessments via other standards.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Requirement might be redundant:

FAC-013-2 R5 already requires the Transfer Capability assessment to be provided to those entities that make a written request, which can easily be the RC and TO.

TPL-001-4 R8 already requires the Planning Assessment to be provided to those entities that make a written request, which can easily be the RC and TO.

FAC-011-4 requires the RC to consider the stability limitations provided by the PC in accordance with FAC-014-3 but perhaps this standard should simply refer to stability limitations identified by the PC in FAC-013 and TPL-001.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1 - SERC

Answer	Yes
Document Name	

Comment

The characteristics of the transmission models (generation dispatch, load levels, topology, etc) used in planning studies are vastly different from those used in analysis of the operational time horizon. Therefore, establishing SOLs based on a planning study, is typically not feasible.

However, there are certain configurations or multiple contingencies that are assessed by planners in accordance with TPL-001-4 that operators may need to be aware of. This is primarily true for instability risks that may not be analyzed in operational studies for some areas. It is up to the RC (and the tools available to them) to determine if establishment of an SOL based on a limitation identified in a planning study is appropriate for its area.

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

Planning horizon information from Planning Assessments (TPL-001-4 standard) and Transfer Capability analyses (FAC-013-2 standard) may help RCs and TOPs become aware of potential operating horizon reliability-related needs. However, actual operating horizon reliability needs can only be determined from studies of operating horizon system conditions and contingencies, which are different from the planning horizon system conditions and planning event contingencies. Information from planning horizon studies only provides ideas or hints of prospective operating horizon reliability-related needs.

Planning Coordinators and Transmission Planners perform (or will begin to perform) planning horizon studies that are beyond the FAC-013-2 and TPL-001-4 standards. These studies are, or will be, performed for the FAC-002-2 (Interconnection Studies) standard, PRC-006-2 standard (UFLS), the present EOP-003-2 and future PRC-010-1 (UVLS) standards, and the present PRC-015-0 and future PRC-012-2 standards (RAS). Study results from these other standards may also be helpful to RCs and TOPs.

Study results that may be helpful to RCs and TOPs are not limited stability results. Steady-state overload, over-voltage, and under-voltage results may also be helpful to RCs and TOPs become aware of prospective operating horizon reliability-related needs.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE

Answer	Yes
Document Name	

Comment

Because equipment may be automatically removed from service without a Fault condition or equipment failure, Part 8.2 should be revised to read:

8.2 The Contingencies or removals from service of equipment which result in the instability

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

There is a need for this information. However, R8 requires each PC and TP to communicate the results of their Transfer Capability assessments, but FAC-013-2 only requires each PC to perform this type of assessment. There is not a requirement for TPs to perform Transfer Capability assessments, but this requirement implies that TPs should perform this assessment. The language should be changed. Also, I believe that it would be more efficient for the PC and TP communicate only the instabilities identified in the assessments instead of providing all of the results of the assessments.

In Requirement R8, Texas RE recommends changing “the results of the stability analysis” to “any instability”.

Texas RE also recommends adding another requirement for each PC and TP should be added that matches Requirement R6.

R9. Each Planning Coordinator and Transmission Planner shall provide any instability identified in its assessments to each affected Transmission Owner and Generation Owner the following:

9.1 The identification of the Facilities that are owned by that entity, which are critical to the derivation of an instability.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

The information in the Planning Assessment and Transfer Capability analysis is important for identifying instability risks. However, BPA believes that the stability results that need to be communicated should be those results where Stability is the defining limit in the near term Planning Horizon. If the SOL is Thermally limited, there is no need to communicate the Stability limit.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	
Document Name	
Comment	
Because Peak is registered as an RC, Peak is not intimately familiar with the various types of studies performed in the planning horizon and whether or not those studies stress the system sufficiently to uncover potential instability risks. So long as instability risks are adequately identified in the planning horizon and communicated to the RC and impacted TOPs in the operations horizon, there may be no need for additional studies.	
Likes 0	
Dislikes 0	
Response	

12. Are there additional “studies” or activities that planners should undertake (beyond those currently required in the current standards, including TPL-001-4 and FAC-013-2) to identify instability risks? If so, please describe.

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. FAC-013 is only applicable to the Planning Coordinator, so the way R8 is worded seems to obligate the TP to provide a Transfer Capability assessment that is not required to have. This is creating a new TP requirement.

2. There are planning horizon studies performed for the PRC-006-2 standard (UFLS), the present EOP-003-2 and future PRC-010-1 (UVLS) standards, and the present PRC-015-0 and future PRC-012-2 standards (RAS) and the results may be of interest or value to RCs and TOPs. We are not aware of any RC or TOP need for additional planning studies.

Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

The requirements in TPL-001-4 are sufficient to test the system for instability for the large majority of occurrences.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

FAC-013 is only applicable to the Planning Coordinator, so the way R8 is worded seems to obligate the TP to provide a Transfer Capability assessment that is not required to have. This is creating a new TP requirement.

Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] FAC-013 is only applicable to the Planning Coordinator, so the way R8 is worded seems to obligate the TP to provide a Transfer Capability assessment that is not required to have. This is creating a new TP requirement.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
Support SPP RTO Comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
As noted in the response to Question 11, Planning Coordinators and Transmission Planners perform (and will begin to perform) planning horizon studies that are beyond the FAC-013-2 and TPL-001-4 standards. These studies are, or will be, performed for the FAC-002-2 (Interconnection Studies) standard, PRC-006-2 standard (UFLS), the present EOP-003-2 and future PRC-010-1 (UVLS) standards, and the present PRC-015-0 and future PRC-012-2 standards (RAS). Study results from these other standards may also be helpful to RCs and TOPs prospective operating horizon reliability-related	

needs.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
We believe that on-line stability assessments should be performed by the RC. Stability studies of specific system conditions in the operating horizon could be performed by the TOP or Operations Planners upon request.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
The contingencies studied per TPL-001-4 is sufficiently thorough for planning analysis. If there is a particular anomaly in an Area that warrants additional analysis, that will be determined by the parties involved on a case-by-case basis.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We subscribe to the MRO NSRF's comment that is provided below:	

There are planning horizon studies performed for the PRC-006-2 standard (UFLS), the present EOP-003-2 and future PRC-010-2 (UVLS) standards, and the present PRC-015-0 and future PRC-012-2 standards (RAS) and the results may be of interest or value to RCs and TOPs. We are not aware of any RC or TOP need for additional planning studies.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1 - FRCC

Answer	No
Document Name	

Comment

The term planners is unclear. Do you mean personnel performing studies to support their TP/PC/PA function or personnel performing studies to support the TOP function?

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: ERCOT does not support the above comment.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The Planning Standards (TPL-00104 & FAC-013-2) should be augmented with True N-1-1, not N-2 without system adjustments, and those finding should be disseminated to the TOPs and RC(s).	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Historically, transmission planner's studies have been concerned with generation in the planner's area serving load in the planner's area. These studies tend to miss reliability risks due to loop-flows or transfers into, out of, or across systems. Transmission planners should be required to study realistic levels of transfers, load and generation dispatch similar to the language in FAC-011-4 R4.3 and share the results with the TOP and Reliability Coordinator. It is imperative that transmission planners are studying the flows on the system that the operators are experiencing in real-time, regardless if the flows are firm, non-firm or loop flows.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	
Document Name	

Comment

Because Peak is registered as an RC, Peak is not intimately familiar with the various types of studies performed in the planning horizon and whether or not those studies stress the system sufficiently to uncover potential instability risks. So long as instability risks are adequately identified in the planning horizon and communicated to the RC and impacted TOPs in the operations horizon, there may be no need for additional studies.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment	
Planners often perform special studies that aren't required for the TPL and FAC standards, and these studies may identify instabilities that need to be communicated. In Requirement R8, Texas RE recommends the changing "the results of the stability analysis" to "any instability" and removing "Planning Assessments and Transfer Capability".	
Likes 0	
Dislikes 0	
Response	

13. With regard to Part 8.3: The SDT believes that the information listed in Part 8.3 is critical for RC and TOP awareness and understanding of the instability risks identified in the planning horizon and the listed mitigation measures employed to address those risks. Do you agree? If not, please explain why you believe it is not critical that the RC and TOP obtain this information from the planning entities?

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
The Part 8.3 information may be of some interest or value to RCs and TOPs, but we do not believe it is critical for RC and TOP awareness and understanding of the instability risks in operations horizon. It is highly unlikely that RAS, UVLS, or UFLS based on planning horizon study system conditions and planning event contingencies are applicable or critical to operating horizon study system conditions or operating event.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
In our opinion the RC should not be concerned for stability results in the planning horizon, which covers system conditions up to 10 years in the future. (The TP should be working to address these stability concerns, before they would be a concern to the RC.) At a minimum, the stability assessment results in requirement R8 should be more narrowly focused to the near-term horizon. If operational awareness of instability risks is that important, then a requirement for a seasonal stability assessment should be added to the TOP standards. We believe this would provide much more useful information than the stability results to satisfy standard TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

Please see our suggestion to remove R8 altogether, under Q11.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe the information in Part 8.3 may be of interest or value to RCs and TOPs, but it is not critical. It is unlikely that RAS, UVLS, or UFLS based on planning horizon study system conditions and planning event contingencies are applicable or critical to operating horizon study system conditions or operating event.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We agree with the comments of the MISO TOP-IRO Task team.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	Yes
Document Name	
Comment	

I agree with this in concept.	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
While Seminole agrees that this information is critical, just as all information related to reliability is critical, we don’t agree that a requirement to distribute results from other standards should be within FAC-014-3. See additional comments in question 14 below.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The Part 8.3 information is critical and may help RCs and TOPs become aware of potential operating horizon reliability-related needs (both steady state and stability). These results provide the RC and TOP an awareness and understanding of risks that are identified in the planning horizon that may occur under other conditions applicable to the operating horizon.	
Likes 0	
Dislikes 0	
Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	

Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS]	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
This is good information to have and be aware of independent of any stability applications or concerns.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Peak believes this information is important for the RC's and TOP's understanding of the full picture.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1 - SERC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that list should include any actions to address instability, which includes the identification of SOLs and IROLs.	
Likes 0	
Dislikes 0	
Response	

14. Do you agree that this proposed requirement is appropriately placed in FAC-014, or do you believe the proposed requirement should be placed in another standard (*i.e.*, TPL-001-4 and FAC-013-2)?

Teresa Cantwell - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
The proposed R8 may fit better in TPL-001.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that R8 is better placed in FAC-13. This will ensure that Planning requirements for establishing and communicating SOL's are located in one standard.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
FAC-011/14 addresses SOL/IROL -methodology, setting, communicating. R8, as written, does not address these issues. The proposed R8 should also include the criteria used by the PC and TP for identifying System instability (ref. TPL-001-4 R6) because these may differ from those defined by the RC in FAC-011 R4.1. However, with the retiring of FAC-010, the revised FAC-011 and FAC-014 should not be applicable to the PC or TP. Any requirement for sharing studies from other standards should be incorporated within the relevant standards (TPL, …). Overall, we think that FAC-011 and FAC-014 should be merged in a single standard applicable to the RC and TOP with regards to the establishment of	

SOL/IROL. Also, there should be more consistency between the TPL standard and FAC-011/014. Although we recognize the differences between the planning and operating functions, those standards have a lot in common in terms of the studies performed to ensure power system reliability.

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
While the requirement can work in FAC-014, they may be a better fit for TPL-001-4 and FAC-013-2. If the requirement exists in these standards, the corresponding requirement in FAC-011 can be revised to reference the new location.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
The proposed R8 may fit better in TPL-001.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe Requirement R8 is partly duplicative of Requirement R3 in IRO-017-1, which will become effective on 4/1/2017. IRO-017-	

1/Requirement R3 obligated PCs and TPs to share their (entire) Planning Assessment with affected RCs. We propose the following:

a. In the near term Requirement R8 be worded as in IRO-017-1/Requirement R3, but obligate PCs and TPs to share their (entire) Planning Assessment with affected TOPs; and

b. In the long term, remove Requirement R8 after IRO-017-1/Requirement R3 is modified to add the obligation to share Planning Assessments with affected TOPs.

However, the Requirement R8.3 obligation to share RAS, UVLS, and UFLS study results (even those unrelated to instability) with RCs and TOPs is not duplicative of other requirements, and may be of some value to RCs and TOPS.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	No
Document Name	

Comment

No these requirements should be identified in TPL-001-4/FAC-013-2 and the TC(TP)/PC should be removed from the list of Applicable entities in FAC-014-3.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

It’s unclear to us what “this proposed requirement” refers to, whether it is R8 or Part 8.3. Regardless, we do not believe R8 is needed and therefore Part 8.3 is also not needed – not in FAC-014 or any other standards.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Con Edison and ISO-NE	
Answer	No
Document Name	
Comment	
Belongs in FAC-013-2 and TPL-001-4. Should not have to refer between standards.	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Requirement R8 is partly duplicative of the Requirement R3 in the IRO-017-1 standard, which will become effective on 4/1/2017.) IRO-017-1_R3 will obligate PCs and TPs to share their (entire) Planning Assessment with affected RCs. As noted in the comments for Question 11 and Question 12, there are other studies performed for other existing or future standards (FAC-002-2, PRC-006-2, EOP-003-2, PRC-010-1, PRC-015-0, and PRC-012-2) that could be placed in FAC-014-3 or the other standards. It may be practical in the near term to place the desired communication requirement in FAC-014-3 for now, and in the long term to have them placed in the applicable standards.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
If it is determined that RCs and TOPs need Planning Assessment stability information from standard TPL-001-4, then this requirement should be added to TPL-001-4 and not included in FAC-014-3. Requirement R8 of standard TPL-001-4 already requires planning study assessment results to be sent to the PC. The RC could be added to this requirement, or the PC could provide this information to the RC.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We believe that this requirement should be placed in TPL-001-4 standard since its reliability objective is fundamentally the same as the existing R8 in TPL-001-4 which requires providing the annual planning assessment to certain functional entities. Note that most of the information specified in sub-parts 8.1 to 8.4 above (other than UVLS and UFLS assessment) is included in the TPL planning assessment. Also, we not that part 8.3 is redundant to part 8.4 - all the mitigation actions listed in part 8.3 as essentially examples of Corrective Action Plans employed in the planning assessment.	
Likes 0	
Dislikes 0	
Response	
Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
The requirement to communicate the information identified in R8 is more appropriately required as part of the standards that requires the analysis, ie. TPL-001-4 and FAC-013-2. Having two individual standards that require analysis and a totally seperate standard with only requirement that requires the analysis of the non-affiliated standards to be communicated to the RC/TOP becomes problematic. Also, FAC-013-2 R5 as written (reference below), does not preclude the RC or TOP as a functional entity, if they so desire, to request the results of the FAC-013 assessment today, so I am not sure what value R8 of FAC-014-3 provides. FAC-013-2 R5: "However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request." In regards to TPL-001-4, Seminole believes it to be more appropriate for the FAC drafting team to communicate a recommendation to the TPL-001-4 SDT to modify R8 of TPL-001-4 to either require the PC to provide the results of its Planning Assessment to the RC and/or TOP or use similar language that is in FAC-013-2 R5 where the language does not preclude any entity that has a reliability need for the results.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
I believe this requirement would be more appropriate in the other standards mentioned. Those standards include other requirements relating to communication of assessment results where this requirement would fit in easily and therefore it would be less likely to be overlooked. It may be necessary, however, to include this requirement in this standard until FAC-008 and FAC-013 can be revised.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1 - FRCC	
Answer	No
Document Name	
Comment	
The proposed requirement should ideally be located in the TPL and FAC standard. That insures that it remains consistent with the standard product that it references and puts it in the logical place. It would not make sense to have a SOL methodology sharing requirement in the TPL standards, so having an assessment sharing requirement in the FAC standard is equally out of place. However practicality of the standards development process may require that it be here in the FAC 14 standard.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
As long as it doesn't result in another standard project, it can stay in FAC-014.	
Likes 0	
Dislikes 0	

Response	
Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
[THESE COMMENTS REPRESENT SPP STAFF COMMENTS] As long as it doesn't result in another standard project, it can stay in FAC-014.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
The purpose of FAC-014 is to establish and communicate SOLs. SOLs are established by the RC based on the analysis the RC deems appropriate for its area, which includes credible instability risks identified in planning studies. FAC-014 appears to be the correct medium to use for the communication of necessary planning information.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS agrees that the RC and TOPs should receive this information, however in FAC-014 AZPS believes it is more appropriate to write the standard from the focus of the RC and TOPs and not from the PC and TPs. The PC and TPs are already required to provide the information via other standards. In FAC-014 the requirement should be for the RC and TOPs to appropriately review the Assessments sent to them from the PC and TPs to increase awareness.	
Likes 0	

Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment
The proposed requirement is appropriately placed in FAC-014, but FAC-013 needs to be enhanced to require the Planning Coordinator to include stability analysis in it's Transfer Capability studies.

Likes 0	
Dislikes 0	

Response

Tammy Porter - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andy Bolivar - NextEra Energy - 1,3,5,6 - FRCC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

We agree with the comments of the MISO TOP-IRO Task team.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

The proposed requirement would be more appropriate in TPL-001-4 since TPL-001-4 already addresses the stability studies and Planning Assessment performed by the PC and TP and this requirement says stability issues identified by the PC and TP should be communicated to its RC and impacted TOPs.

Likes 0	
Dislikes 0	

Response

Unofficial Comment Form for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

Before submitting comments with regard to the proposed changes to FAC-014-3, please review the background information section provided in the “Unofficial Comment Form for FAC-011-4.” That document contains foundational information that must be reviewed in order to have a complete understanding of the proposed changes to FAC-014-3.

Proposed Revisions, Background Information and Questions

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 1: Do you agree with that the Reliability Coordinator (RC) should have primary responsibility for establishing IROLs for its RC Area? If not, please provide your comments on the appropriate break down of responsibilities (between RC and TOP) in establishing IROLs.

☒ Yes

☐ No

Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 2: The proposed revisions work together with the proposed revisions to the definition of SOL. The new requirement makes clear that the TOP will establish SOLs in accordance with the RC SOL Methodology. This means that the TOP will follow the RC Methodology to determine: applicable Facility Ratings for use in operations (see, proposed FAC-011-4 Requirement R2); applicable steady-state System

voltage limits to be used in operations (see, proposed FAC-011-4 Requirement R3); and, the applicable stability limitations, if any, that are to be used in operations (see, proposed FAC-011-4 Requirement R4). Do you believe that it is clear that the TOP must establish SOLs in accordance with what is outlined in the RC Methodology?

☐ Yes

☒ No

Comments: It is unclear that the TOP must establish all stability limits since R3 infers that this is solely an RC responsibility. This should be clarified by identifying each of the 3 types of limits in R2.

<u>Question 3</u>: TOP application of the RC Methodology will always result in identification of the appropriate Facility Ratings and steady-state System voltage limits, however, it may not always result in identification of stability limitations (this is *only if* there are no applicable limitations specific to the TOP). If there are appropriate stability limitations (identified as a result of implementing the RC method for determining the stability limitations in proposed FAC-011-4 Requirement R4), then the TOP will identify these SOLs. Do you believe this is clear from the language of the requirements (both in FAC-14-3 Requirement R2 combined with the proposed revisions to FAC-011)?

☐ Yes

☒ No

Comments: It is unclear that the TOP must establish all stability limits since R3 infers that this is solely an RC responsibility. This should be clarified by identifying each of the 3 types of limits in R2.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies,	**<u>Mapping to existing FAC standards under revision:</u>** • <u>N/A</u>: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an “IROL,” and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically “IROLs.” For example, there may be instances of local, contained instability that are not appropriately designated an “IROL,” because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger	

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Question 4: Do you believe that the RC should be responsible for establishing stability limitations used in operations where more than one TOP is impacted?

☒ Yes
☐ No
Comments:

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.	(pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	

Question 5: Do you agree that the RC should be the only entity responsible for providing other entities within its RC Area the established SOLs? If no, do you believe the entity that establishes the SOL (either the RC *or the TOP*) should be the entity that communicates the SOL to other entities? Please explain.

☐ Yes

☒ No

Comments: The RC should not be the only entity responsible for providing other entities the established SOLs. The entity that establishes the SOL should communicate the SOL to the rest of the entities within the same RC area to provide a common source of information.

Question 6: With regard to proposed Part 4.1: Do you believe that the language provides sufficient clarity regarding what is required for communicating updates to dynamically updated limits? If not, what language do you propose?

☐ Yes

☒ No

Comments: Instead of RCs, TOPs should communicate the SOLs they establish, including dynamically updated limits, consistent with R2 as well.

Question 7: With regard to proposed Part 4.1: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the communications, or should the RC have flexibility in determining what is appropriate for its particular RC Area?

☐ Yes

☒ No

Comments: The RC or TOP should have flexibility in setting a time requirement. However, entities in the same RC area should agree to a time requirement that allows the entity receiving the data to be consistent with the timeframe specified in IRO-010-2 and TOP-003-3.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL. **5.2.** The value of the IROL and its associated IROL T_V. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Question 8: Do you agree with the information identified in Parts 5.1 through 5.4? Is there any additional information that the RC should provide regarding IROLs? Are there any additional entities that should be included in this requirement and receive the information from the RC?

☒ Yes
☐ No

Comments: It may be a good idea to identify if it is a static value, fixed value, or dynamically calculated value.

Proposed Reliability Standard: FAC-014-3, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed Reliability Standard: FAC-014-3, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	operator information not appropriate for open-ended sharing.	

<u>Question 9</u>: In consideration of the FERC directive regarding communicating IROL information to the Transmission Owner, do you agree with this proposed new requirement? If not, please explain the basis for why you do not support the proposed requirement, and the alternative language you are proposing to address the issues raised in FERC Order No. 777.

☒ Yes
☐ No
Comments: ERCOT asks the SDT to consider simplifying R6 and R6.1 into a single requirement.

<u>Question 10</u>: Do you believe a specific timeframe should be included that sets the minimum acceptable time for when the RC must provide the information to the Transmission Owner and Generator Owner?

☐ Yes
☒ No
Comments: No, a specific timeframe should not be included. If the SDT decides to include a timeframe, ERCOT requests it be consistent with other standards, (e.g. 30 days).

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the	The SDT did not make substantive changes to this requirement; however, the requirement previously existed	**<u>Mapping to existing FAC standards under revision:</u>**

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Transmission Service Providers that share its portion of the Reliability Coordinator Area.	as a "part" of a requirement and it is now a stand-alone requirement.	• FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Question: None.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability,	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP.	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	

Question 11: Do you agree that there is a reliability-related need for the RCs and TOPs to obtain the information from the Planning Assessment and Transfer Capability analysis for the purpose of identifying instability risks when establishing SOLs (and IROLs)? Are there other "studies" that are currently performed that should also be included in this communication requirement?

☒ Yes
☐ No

Comments: UVLS studies may also identify instability risks.

Question 12: Are there additional "studies" or activities that planners should undertake (beyond those currently required in the current standards, including TPL-001-4 and FAC-013-2) to identify instability risks? If so, please describe.

☐ Yes
☒ No
Comments: RCs and TOPs should conduct the additional “studies” to ensure they have an operational perspective, whether planning staff or some other contractor performs the task in their behalf.

<u>Question 13</u>:With regard to Part 8.3: The SDT believes that the information listed in Part 8.3 is critical for RC and TOP awareness and understanding of the instability risks identified in the planning horizon and the listed mitigation measures employed to address those risks. Do you agree? If not, please explain why you believe it is not critical that the RC and TOP obtain this information from the planning entities?
☒ Yes
☐ No
Comments:

<u>Question 14</u>: Do you agree that this proposed requirement is appropriately placed in FAC-014, or do you believe the proposed requirement should be placed in another standard (*i.e.*, TPL-001-4 and FAC-013-2)?
☒ Yes
☐ No
Comments:

Proposed Definitions of:
"System Operating Limit" (SOL) and "SOL Exceedance"

Term: "System Operating Limit" (SOL)

Revised Definition:

Facility Ratings, System Voltage Limits, and stability limits used in the operation of the BES.

Redline Definition:

Facility Ratings, System Voltage Limits, and stability limits used in the operation of the BES.

~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings, (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits, (applicable pre- and post-Contingency voltage limits)~~

Term: "SOL Exceedance"

Definition:

An operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring, Real-time Assessments (RTA) or Operational Planning Analysis (OPA):

The pre-Contingency state indicates any of the following:

- Actual flow through a Facility is above the Facility's Normal Rating
- Actual bus voltage is outside normal System Voltage Limits
- A stability limit established to prevent instability without a Contingency is exceeded
- A stability limit established to prevent the Contingency from resulting in instability is exceeded

The calculated post-Contingency state indicates any of the following:

- Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur

- Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur
- Defined stability performance criteria are not met

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Standards Authorization Request Form

When completed, email this form to:
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NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Establish and Communicate System Operating Limits		
Date Submitted:	September 29, 2017		
SAR Requester Information			
Name:	Project 2015-09 SDT		
Organization:	NERC		
Telephone:	404.446.9691	E-mail:	steven.noess@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard ☒ Revision to existing Standard		☒ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The project will revise requirements for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES).
Industry Need (What is the industry problem this request is trying to solve?):
FAC standards fulfill an important reliability objective for determining and communicating SOLs used in the reliable planning and operation of the Bulk Electric System (BES). Revisions are necessary to improve the requirements by eliminating overlap with approved Transmission Planning (TPL) requirements, enhancing consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs).

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed standards project will revise the requirements for determining and communicating SOLs and IROLs to address issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards. The resulting standard(s) and definition(s) will benefit reliability by improving alignment with approved TPL and proposed TOP and IRO standards. The project may result in development of one or more proposed Reliability Standards and definitions and may consolidate reliability objectives from the existing three Reliability Standards. Where necessary, the standard drafting team (SDT) will review and modify existing Reliability Standards and NERC Glossary terms (definitions) for incorporating the new and/or revised definitions.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The standards development project will consider recommendations from Project 2015-03 Periodic Review of System Operating Limits. This review included inputs from the Independent Experts Review Project (IERP), FERC Directives, and Paragraph 81 concepts. When completed, the project will address all issues identified in the Periodic Review Recommendations (PRRs) for FAC-010-3, FAC-011-3, and FAC-014-2, including: • <u>Propose retirement of FAC-010-3.</u> BES planning is covered under approved TPL-001-4 which provides comprehensive requirements for a variety of contingencies. The standards project will propose retirement of FAC-010-3. • <u>Clarify acceptable System performance criteria for the operations time horizon.</u> The proposed standards project will develop continent-wide standards for system performance in the operations time horizon to replace currently-enforceable requirements in FAC-011-3 that specify acceptable system performance through the Reliability Coordinator's (RC) SOL methodology. Development of a table similar to TPL-001-4 Table 1 with appropriate requirements for the operations time horizon would enhance clarity and consistency. This project will determine the appropriate family of standards for this table. • <u>Propose requirements to address identified reliability issues.</u> Requirement(s) will be developed to address FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (P6 and P41). FERC Order No. 777 states: *“As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners.”* (P 6) *“NERC should establish a clearly defined communication structure to assure that IROLs and*

SAR Information
changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41) • <u>Revise or develop new definitions to provide clarity and alignment with how SOLs are treated in proposed TOP and IRO standards developed in Project 2014-03 Revisions to TOP and IRO Standards.</u> This work may include, but is not limited to, revising the definition of System Operating Limit (SOL) and creating a new definition for SOL Exceedance. The project will also address the issues identified in the FAC PRRs related to the application of the IROL term. Proposed definitions should provide clarity and consistency to establishing SOLs and IROLs and promote a common understanding of what it means to establish and exceed SOLs. The SDT will review the existing body of NERC Reliability Standards and NERC Glossary terms (definitions) and where appropriate, modify those standards and definitions by incorporating the new terms and/or definitions of SOL Exceedance and System Voltage Limit, as well as the revised definition of SOL. The SDT will coordinate with other drafting teams on relevant standards as necessary. • <u>Clarify responsibilities for establishing and communicating SOLs.</u> The project will propose requirements to clearly delineate the functional entity responsibilities for determining and communicating each type of SOL (Facility Ratings, System voltage limits, voltage stability limits, and transient stability limits) where not already addressed in existing standards (*e.g.*, FAC-008). • <u>Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating System Operating Limits.</u> Revise requirements to conform to the Results-Based Standards format, functional entity terms found in the NERC Functional Model, guidelines for compliance elements, and NERC standards for content and quality (Independent Experts Review Project).

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards	
Standard No.	Explanation
FAC-010-3	Project 2015-03 PRR recommends retirement.
FAC-011-3	Project 2015-03 PRR recommends revision.

Related Standards	
FAC-014-2	Project 2015-03 PRR recommends revision.
FAC-015-1	Project 2015-09 SDT proposed new.
Other standards and NERC Glossary terms/definitions	Project 2015-09 SDT proposed revisions, as required to account for the use of any new and modified NERC Glossary definitions.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	Regional Differences (Section E) is being reviewed through the WECC standards process.

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The proposed standards project will revise the requirements for determining and communicating SOLs and IROLs to address issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards. The resulting standard(s) and definition(s) will benefit reliability by improving alignment with approved TPL and proposed TOP and IRO standards. The project may result in development of one or more proposed Reliability Standards and definitions and may consolidate reliability objectives from the existing three Reliability Standards. Where necessary, the standard drafting team (SDT) will review and modify existing Reliability Standards and NERC Glossary terms (definitions) for incorporating the new and/or revised definitions.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The standards development project will consider recommendations from Project 2015-03 Periodic Review of System Operating Limits. This review included inputs from the Independent Experts Review Project (IERP), FERC Directives, and Paragraph 81 concepts. When completed, the project will address all issues identified in the Periodic Review Recommendations (PRRs) for FAC-010-3, FAC-011-3, and FAC-014-2, including: • <u>Propose retirement of FAC-010-3.</u> BES planning is covered under approved TPL-001-4 which provides comprehensive requirements for a variety of contingencies. The standards project will propose retirement of FAC-010-3. • <u>Clarify acceptable System performance criteria for the operations time horizon.</u> The proposed standards project will develop continent-wide standards for system performance in the operations time horizon to replace currently-enforceable requirements in FAC-011-3 that specify acceptable system performance through the Reliability Coordinator's (RC) SOL methodology. Development of a table similar to TPL-001-4 Table 1 with appropriate requirements for the operations time horizon would enhance clarity and consistency. This project will determine the appropriate family of standards for this table. • <u>Propose requirements to address identified reliability issues.</u> Requirement(s) will be developed to address FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (P6 and P41). FERC Order No. 777 states: *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners."* (P 6) *"NERC should establish a clearly defined communication structure to assure that IROLs and*

SAR Information
changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41) • Revise or develop new definitions to provide clarity and alignment with how SOLs are treated in proposed TOP and IRO standards developed in Project 2014-03 Revisions to TOP and IRO Standards. This work may include, but is not limited to, revising the definition of System Operating Limit (SOL) and creating a new definition for SOL Exceedance. The project will also address the issues identified in the FAC PRRs related to the application of the IROL term. Proposed definitions should provide clarity and consistency to establishing SOLs and IROLs and promote a common understanding of what it means to establish and exceed SOLs. The SDT will review the existing body of NERC Reliability Standards and NERC Glossary terms (definitions) and where appropriate, modify those standards and definitions by incorporating the new terms and/or definitions of SOL Exceedance and System Voltage Limit, as well as the revised definition of SOL. The SDT will coordinate with other drafting teams on relevant standards as necessary. • Clarify responsibilities for establishing and communicating SOLs. The project will propose requirements to clearly delineate the functional entity responsibilities for determining and communicating each type of SOL (Facility Ratings, System voltage limits, voltage stability limits, and transient stability limits) where not already addressed in existing standards (*e.g.*, FAC-008). • Develop revised or new requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating System Operating Limits. Revise requirements to conform to the Results-Based Standards format, functional entity terms found in the NERC Functional Model, guidelines for compliance elements, and NERC standards for content and quality (Independent Experts Review Project).

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards	
Standard No.	Explanation
FAC-010-3	Project 2015-03 PRR recommends retirement.
FAC-011-3	Project 2015-03 PRR recommends revision.

Related Standards	
FAC-014-2	Project 2015-03 PRR recommends revision.
FAC-015-1	Project 2015-09 SDT proposed new.
Other standards and NERC Glossary terms/definitions	Project 2015-09 SDT proposed revisions, as required to account for the use of any new and modified NERC Glossary definitions.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	Regional Differences (Section E) is being reviewed through the WECC standards process.

Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits (SOL and SOL Exceedance Definitions)

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2015-09 Establish and Communicate System Operating Limits** project, SOL and SOL Exceedance definitions. The electronic form must be submitted by **8 p.m. Eastern, Monday, October 30, 2017**.

Documents and information about this project are available on the project page. If you have questions, contact either Senior Standards Developer, Darrel Richardson at (609) 613-1848 or Al McMeekin at (404) 446-9675.

Background Information

As part of Project 2015-09, the standard drafting team (SDT) is proposing a revision to the definition of System Operating Limit (SOL), and is proposing a new definition for SOL Exceedance. The rationales for these definitions are captured in the accompanying document. It is critical that commenters read the accompanying definitions rationales prior to completing this comment form to understand why these definitions are being proposed and why they are crafted the way they are. The two definitions SOL and SOL Exceedance work together to clearly identify what SOLs are and what it means to exceed them.

One of the objectives of the SOL and SOL Exceedance definition is to codify the concepts in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which served as a conceptual basis for the development of the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) standards that were modified as part of Project 2014-03. The Project 2015-09 SDT recognizes that while the Project 2014-03 Whitepaper provided clarity on the SOL and SOL exceedance concepts, reliability would be further enhanced by modifying the SOL definition in the NERC Glossary and developing a new defined term SOL Exceedance to better align the definitions in the NERC Glossary with that whitepaper and the manner in which the SOL concept is used in the TOP/IRO Reliability Standards. The SDT believes that the proposed SOL and SOL Exceedance definitions and the proposed related FAC standards improve reliability by creating better alignment with the currently effective Transmission Planning, TOP, and IRO standards, improving clarity, and reducing redundancy.

In addition to the *System Operating Limit and SOL Exceedance Rationale*, the SDT has provided the *SOL Definition Impact* spreadsheet for review. This spreadsheet identifies every occurrence of the SOL term in the body of standards, which includes those that are subject to enforcement, those that are subject to future enforcement, and those that are filed and pending regulatory approval, and those that are pending regulatory filing. The *SOL Definition Impact* spreadsheet identifies not only occurrences of the SOL term in the requirements, but also includes occurrences of the term in purposes, measures, VSLs, Attachments, Guidelines and Technical Basis, and other definitions. Each occurrence contains a recommendation of changes, if any, including recommendations for standards that should be modified to integrate the SOL Exceedance term.

If the industry sees value in modifying the definition of SOL and creating a definition for SOL Exceedance, the SDT expects to follow this posting for comment with a subsequent posting for ballot of the revised SOL definition, the new SOL Exceedance definition, and the revised Reliability Standards that incorporate the new SOL Exceedance definition.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. Industry responses to the initial posting for informal comment in July of 2016 indicated general support for revising the SOL definition. Since that time, a few key events have occurred that may relate to the need for modifying the definition of SOL:
    a. In Order 817 FERC approved the TOP and IRO standards which became effective on April 1 of 2017.
    b. The NERC SOL Whitepaper entitled, “System Operating Limit Definition and Exceedance Clarification” which served as a conceptual basis for these TOP and IRO standards was referenced in paragraph 69 of FERC Order 817.
    c. The NERC SOL Whitepaper is included in the list of ERO Enterprise-endorsed Implementation Guidance documents in the Compliance Guidance section of NERC’s website.

    Given the above, and considering the rationale provided in the supporting document, do you support the SDT’s proposal to revise the current SOL definition? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need to modify the SOL definition at all.) Please explain your response.

    ☐ Yes
    ☐ No

    Comments:

2. Industry responses to the initial posting for informal comment in July of 2016 indicated general support for creating a new definition for SOL Exceedance. Since that time, a few key events have occurred that may relate to the need for creating a new definition for SOL Exceedance:
    a. In Order 817 FERC approved the TOP and IRO standards which became effective on April 1 of 2017.
    b. The NERC SOL Whitepaper entitled, “System Operating Limit Definition and Exceedance Clarification” which served as a conceptual basis for these TOP and IRO standards was referenced in paragraph 69 of FERC Order 817.

c. The NERC SOL Whitepaper is included in the list of ERO Enterprise endorsed Implementation Guidance documents in the Compliance Guidance section of NERC's website.

Despite these key events, many TOP and IRO standards require specific action based on SOL exceedances. For example, TOP-001-3 Requirement R14 states, *"Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment."* The initiation of a TOP's Operating Plan per Requirement R14 depends completely on that particular TOP's interpretation of what it means to exceed an SOL. Several other TOP and IRO standards a similarly structured, where the actions taken in accordance with that requirement are governed by the TOP's or Reliability Coordinator's (RC) interpretation of what it means to exceed an SOL. As explained in the definitions rationales, the SDT contends that the absence of a definition could result in inconsistent interpretations of SOL exceedance that could compromise the intent of the standards and ultimately could compromise reliability. For this reason, the SDT is proposing to define SOL Exceedance and to incorporate that definition into the body of Reliability standards as described in the SOL Definitions Impact spreadsheet.

Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to create and implement a definition for SOL Exceedance? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need for having a definition of SOL Exceedance.) Please explain your response.

☐ Yes
☐ No

Comments:

3. The definitions rationales describe the improved clarity and consistency gained by the revised SOL definition. With the proposed definition, it is clear that SOLs are an input to Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs), where the OPA and RTA are used to determine whether those SOLs are being exceeded for the pre- and post-Contingency states, given system conditions. This revised definition is designed to make use of the new TOP and IRO requirements for RCs and TOPs to perform OPAs and RTAs.

   Facility Ratings and System Voltage Limits are not determined by a "study"; rather they are inputs to the "study". On the other hand stability limits are determined through a "study"; however they are still inputs into the OPA and RTA process. FAC-011-4 Requirement R4 and subparts addresses the establishment of stability limits. Under the proposed definition, SOLs are simply the Facility Ratings, System Voltage Limits, and stability limits used in operations, which necessitates their use as an input into OPAs and RTAs.

Considering the simplified approach to SOLs described here and the explanations provided in the definitions rationales, do you agree with the proposed SOL definition? Please explain your response and/or provide alternative language.

☐ Yes
☐ No

Comments:

4. The definitions rationales provide a rationale for the need for a definition for SOL Exceedance. The proposed definition for SOL Exceedance is intended to codify the concepts in the NERC SOL Whitepaper which describes SOL exceedance as unacceptable system performance for the pre- or post-Contingency states with regard to Facility Ratings, System Voltage Limits, and stability limits. The proposed definition of SOL Exceedance along with the proposed definition of SOL describes what SOLs are and what it means to exceed them.

   Considering the explanations provided in the definitions rationales, do you agree with the proposed SOL Exceedance definition? Please explain your response and/or provide alternative language.

   ☐ Yes
   ☐ No

   Comments:

5. The post-Contingency portion of the proposed definition of SOL Exceedance includes three bullet items. This question focuses on the third bullet item:

   > The calculated post-Contingency state indicates any of the following:
   > - Defined stability performance criteria are not met

   The definitions rationales describe the intent of this bullet. In summary, established stability limits are not addressed by this bullet; established stability limits are addressed by the third and fourth bullet under the pre-Contingency state portion of the SOL Exceedance definition. This bullet is intended to apply only to those TOPs or RCs that additionally use real-time tools to determine whether or not defined stability performance criteria are being met in real-time operations in response to Contingency events. As is described in the definitions rationales, the SDT contends that any instance of not meeting stability performance criteria as indicated by these technologies should be considered as an SOL Exceedance because it triggers the appropriate response of the implementation of an Operating Plan to mitigate the condition. This use of real-time tools in this manner, however, does not make use of an established limit (i.e., a "value"); rather, the system is evaluated against defined stability performance criteria to determine if that criteria is being met or not. (Note that FAC-011-4, Requirement R4, Part 4.1 requires the RC's SOL Methodology to specify stability performance criteria.) If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance.

Considering the explanations provided here and further explained in the definitions rationales, do you agree that the proposed SOL Exceedance definition should include this bullet item? Please explain your response and/or provide alternative language.

☐ Yes
☐ No

Comments:

6. The SAR is being revised to authorize the SDT to review the existing body of Reliability Standards and NERC Glossary of terms, and where necessary, modify those standards and definitions to incorporate the new terms and/or definition(s) of SOL Exceedance and System Voltage Limit, as well as the revised definition of System Operating Limit. The SDT has identified the standards and terms they contend would benefit from this incorporation and has included them in separate documents with this posting for your review. Do you agree with the SDT's selections? If not, please explain your response.

   ☐ Yes
   ☐ No

   Comments:

7. If you have any other comments **that you haven't already provided** in response to the above questions, please provide them here.

   Comments:

NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL ") and the definition for the new term "SOL Exceedance" to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed new and modified term is to provide greater clarity and consistency in establishing SOLs and develop a common understanding of what it means to exceed SOLs.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and

2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

The first principle (i.e., know the Facility Ratings, voltage limits, and stability limits) is accomplished through the definition of SOL and Reliability Standards FAC-011 and FAC-014. The SOL values used in operations are determined pursuant to methodologies required by the Facilities Design, Connections and Maintenance ("FAC") group of Reliability Standards. Specifically, currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for developing SOLs (and criteria for identifying Interconnection Reliability Operating Limits ("IROLs")) within its Reliability Coordinator Area. Further, under currently-effective Reliability Standard FAC-014-2, TOPs must establish SOLs consistent with the RC's methodology and RC must determine which of those SOLs are IROLs.

The second principle (i.e., observing the SOLs in both the pre- and post-Contingency state) is accomplished through the requirements in the TOP/IRO Reliability Standards. Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards approved in Order No. 817,[1] TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Specifically, during the operations planning time horizon, RCs and TOPs must perform Operational Planning Analyses ("OPAs") to assess whether the planned operations for the next-day will exceed SOLs (including IROLs) within their area.[2] If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[3] Additionally, in Real-time, RCs and TOPs must perform Real-time Assessments ("RTAs") every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[4] If the RTA identifies any such exceedances, the RC and TOP must initiate an Operating Plan to mitigate the SOL exceedance.[5] If there is an expected or actual IROL exceedance identified in the RTA, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[6]

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop

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1 *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

2 IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

3 IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

4 IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

5 IRO-008-2, Requirement R5; TOP-001-3, Requirement R14.

6 IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. These two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards. In addition to revising the SOL definition and developing a definition for a new NERC Glossary term SOL Exceedance, the SDT for Project 2015-09 also developed a definition for a new NERC Glossary term System Voltage Limit to provide additional clarity and a common understanding as to the meaning of system voltage limits.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

Facility Ratings, System Voltage Limits, and stability limits used in the operation of the BES.

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs are the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.

Furthermore, as discussed in detail below, the SDT determined that references to "most limiting criteria", "specified system configuration", "acceptable reliability criteria", and "pre- and post-contingency" in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL. These phrases are no longer necessary since they are reliable operations concepts that are addressed in the new TOP/IRO Reliability Standards, the proposed FAC-011-4 Requirement R4, and further reinforced with the proposed definition of SOL Exceedance.

<u>Most limiting Criteria</u> – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Aanalysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria."

Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of a Facility Rating, System Voltage Limit, and stability limit.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of identifying instability risks in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4.

<u>Specified System Configuration</u> – The SDT proposes to remove reference to a "specified system configuration" as that concept is also subsumed within the TOP/IRO Reliability Standards. Specifically, in performing OPAs and RTAs, RCs and TOPs must consider specified system conditions such as transmission and generation outages, generation output levels, and load levels. Further, the majority of Facility Ratings and System Voltage Limits are not dependent upon system configuration whereas stability limits are frequently dependent on system configuration. System configuration for the establishment of stability limits is addressed in proposed FAC-011-4, Requirement R4. Because the "specified system condition" is addressed within the definition of OPA and RTA, and because it is also addressed in FAC-011-4 requirement R4 for instability issues, including the phrase "specified system configuration" in the definition of SOL is redundant, unnecessary, and may cause confusion.

<u>Acceptable Reliability Criteria</u> – As with the above two components, the "acceptable reliability criteria" concept is best addressed through requirement language. The SDT determined that the SOL definition should focus simply on what constitutes an SOL and the requirements should focus on methodologies for establishing those SOLs and on ensuring that they are honored in OPAs and RTAs to provide for reliable

operations. Requirement R4 of proposed FAC-011-4 requires the RC to specify stability performance criteria in its SOL Methodology for single Contingencies and for identified multiple Contingencies. Further, the proposed definition of SOL Exceedance addresses stability performance and specifies the reliability criteria for Facility Ratings and System voltage limits for the pre- and post-Contingency states. Taken together with the requirement to study the limits in OPAs and RTAs, the revised FAC-011 and the new definition of SOL Exceedance addresses operation within acceptable reliability criteria.

Pre- and Post-Contingency – The current SOL definition specifies for each of the listed operating limits that it is for pre- and post-contingency states. The SDT determined that the SOL definition need not include such specificity. First, the definitions of OPA and RTA include pre- and post-Contingency analysis. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[7] and because the pre- and post-Contingency states are included in the definition of OPA and RTA, there is no need to duplicate the "pre- and post-Contingency" language in the definition of SOL. Additionally, the pre- and post-Contingency concept is inherent in the definition of some SOLs. For example, many stability limits are defined to prevent instability for specified Contingency events. Accordingly, the pre- or post-contingency nature of an established stability limit would be covered by FAC-014-4 Requirement R4 instead of through the SOL definition. Furthermore, the pre- and post-Contingency operating conditions are addressed in the proposed definition of SOL Exceedance as it relates to Facility Ratings, System voltage Limits, and stability limits.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[8] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. The proposed definition of SOL Exceedance is discussed below.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

SOL Exceedance Definition

Many of the TOP/IRO Reliability Standards use the phrase "SOL exceedance" or otherwise reference the concept of "exceeding an SOL." As discussed above, the actual, potential, or expected exceedance of an SOL as identified by OPAs and RTAs requires applicable RCs and TOPs to develop Operating Plans and take

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[7] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[8] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

mitigating action in accordance with those Operating Plans to address the exceedance. Without a clear and consistent understanding of what it means to exceed an SOL, however, RCs and TOPs may apply the requirements in the TOP/IRO Reliability Standards inconsistently, which could result in widely varying reliability performance. For example, TOP-001-3 Requirement R14 states:

> R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

The initiation of a TOP's Operating Plan per Requirement R14 depends completely on that particular TOP's interpretation of what it means to exceed an SOL. One TOP might interpret SOL exceedance to not include the post-Contingency state when identifying SOL exceedance; rather, it would look only to pre-Contingency (or actual) flows to make that determination. Such an interpretation, however, compromises reliability and is not consistent with the intent behind the SOL exceedance concept, as described in the Project 2014-03 Whitepaper, upon which the TOP/IRO Reliability Standards are based. Nevertheless, because there is no definition of the phrase "SOL exceedance" or specific requirements on how to identify an SOL exceedance, nothing prevents a Transmission Operator from adopting such an interpretation.

To ensure there is a common understanding of what it means to exceed an SOL, the Project 2015-09 SDT proposes to add the term SOL Exceedance to the NERC Glossary with the following definition:

> *An operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring, Real-time Assessments (RTA) or Operational Planning Analysis (OPA):*
>
> *The pre-Contingency state indicates any of the following:*
>
> - *Actual flow through a Facility is above the Facility's Normal Rating*
> - *Actual bus voltage is outside normal System Voltage Limits*
> - *A stability limit established to prevent instability without a Contingency is exceeded*
> - *A stability limit established to prevent the Contingency from resulting in instability is exceeded*
>
> *The calculated post-Contingency state indicates any of the following:*
>
> - *Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*
> - *Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur*
> - *Defined stability performance criteria are not met*

The following is a discussion of each of the components in the proposed SOL Exceedance definition:

Component #1 – *An operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring, Real-time Assessments (RTA) or Operational Planning Analysis (OPA):*

The TOP/IRO Reliability Standards require the RC and the TOP to perform OPAs to assess whether its planned operations for the next day will exceed any of its SOLs. Per the definition of OPA, these assessments must address both the pre-Contingency state and the post-Contingency state based on expected system conditions. If the OPA identifies an SOL exceedance, the TOPs and RC are required to develop an Operating Plan(s) to address the SOL exceedances identified in the OPA. SOL exceedances are also identified as part of Real-time monitoring and RTAs. Per the definition of RTA, these assessments must address both the pre-Contingency state and the post-Contingency state using real-time data. If Real-time monitoring or the RTA identifies an SOL exceedance, the TOPs and RC are required to implement an Operating Plan to address that SOL exceedance. Accordingly, an SOL exceedance is fundamentally an identified operating condition or an expected or potential operating conditioned determined by an analysis of system conditions or expected system conditions.

Component #2 – *The pre-Contingency state indicates any of the following; The calculated post-Contingency state indicates any of the following*

As is discussed in the Project 2014-03 Whitepaper, unacceptable system performance for either the pre- or the post-Contingency state translates to an SOL exceedance. Consistent with the Project 2014-03 Whitepaper, the proposed definition of SOL Exceedance is based on the system performance requirements described in FAC-011-3 Requirement R2.1 and R2.2, which address both the pre- and post-Contingency states.

The proposed definition refers to the "*calculated* post-Contingency state." That is because when OPAs and RTAs are performed, RCs and TOPs use the analysis tools or processes to determine, or calculate, how the system is expected to perform in response to Contingency events.

The proposed definition does not specify whether the post-Contingency state is applicable to single Contingencies or multiple Contingencies. The SDT intends for this issue to be addressed in the RC's SOL Methodology. Currently-effective Reliability Standards FAC-011-3 Requirement R2.2 provides that acceptable system performance for the post-Contingency state is applicable to the single Contingencies specified in Requirements R2.2.1 through R2.2.3. These same single Contingencies are addressed in proposed FAC-011-4 Requirement R5.1.1. Nevertheless, some RCs establish stability limits for certain multiple Contingency events. Per proposed FAC-011-4, Requirements R5.3 and R5.4, the RC's SOL Methodology is required to specify which multiple Contingencies are required to be included for the establishment of stability limits and for stability performance in OPAs and RTAs.

Component #3 – *The pre-Contingency state indicates: … Actual flow through a Facility is above the Facility's Normal Rating*

The SDT determined that any persistent exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an acceptable duration.[9] This approach accomplishes the intended reliability objective of triggering the appropriate action (i.e., implementing an Operating Plan to address the exceedance). If such an exceedance is identified during an OPA, the relevant TOP or RC must have an Operating Plans to mitigate the SOL Exceedance. If identified in an RTA, an actual SOL Exceedance triggers the implementation of Operating Plans to mitigate the SOL Exceedance. The specifics and the timing of those mitigating actions must be contained in the Operating Plan.

Component #4 – *The pre-Contingency state indicates: … Actual bus voltage is outside normal System Voltage Limits*

The language in this component mirrors the language in the preceding bullet applicable to Facility Ratings. The same concepts described above apply.

Component #5 – *The pre-Contingency state indicates: … A stability limit established to prevent instability without a Contingency is exceeded*

The SDT concluded that it is possible to establish a limit to prevent instability from occurring without a Contingency. For example, transfer analyses might indicate that at a certain level of MW transfer over a Facility, the knee of a PV curve is reached without a Contingency. While such limits might not be as common as those that are associated with a Contingency, it is possible for such pre-Contingency instability conditions to occur, therefore it is included in the SOL Exceedance definition as these instances should be addressed in an Operating Plan. Such limits are often established through studies performed one or more days prior to Real-time, though the value of such a limit may be calculated in Real-time. If the TOP or RC does not establish this type of stability limit, then this component of the SOL Exceedance definition would not apply to that TOP or RC.

Component #6 – *The pre-Contingency state indicates: … A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The majority of stability limits are established to prevent instability from occurring in the event of certain Contingencies. When the system is operated within this type of stability limit, it is expected that the system would remain stable should any of the identified Contingencies occur. Conversely, when this type of stability limit is being exceeded, the system is not expected to remain stable should any of the identified Contingencies occur. While this type of stability limit is monitored in the pre-Contingency state, it actually addresses post-Contingency instability. For example, a transmission interface might have a voltage stability limit of 1000 MW to prevent Contingency X from resulting in voltage instability. If flow on the interface is kept below 1000 MW, the system is expected to remain stable should Contingency X occur; however, if flow on the interface exceeds 1000 MW, the system is expected to experience voltage instability should Contingency X occur. These types of stability limits are typically established through studies performed one or more days prior to Real-time; however, the value of these limits may be calculated in real-time.

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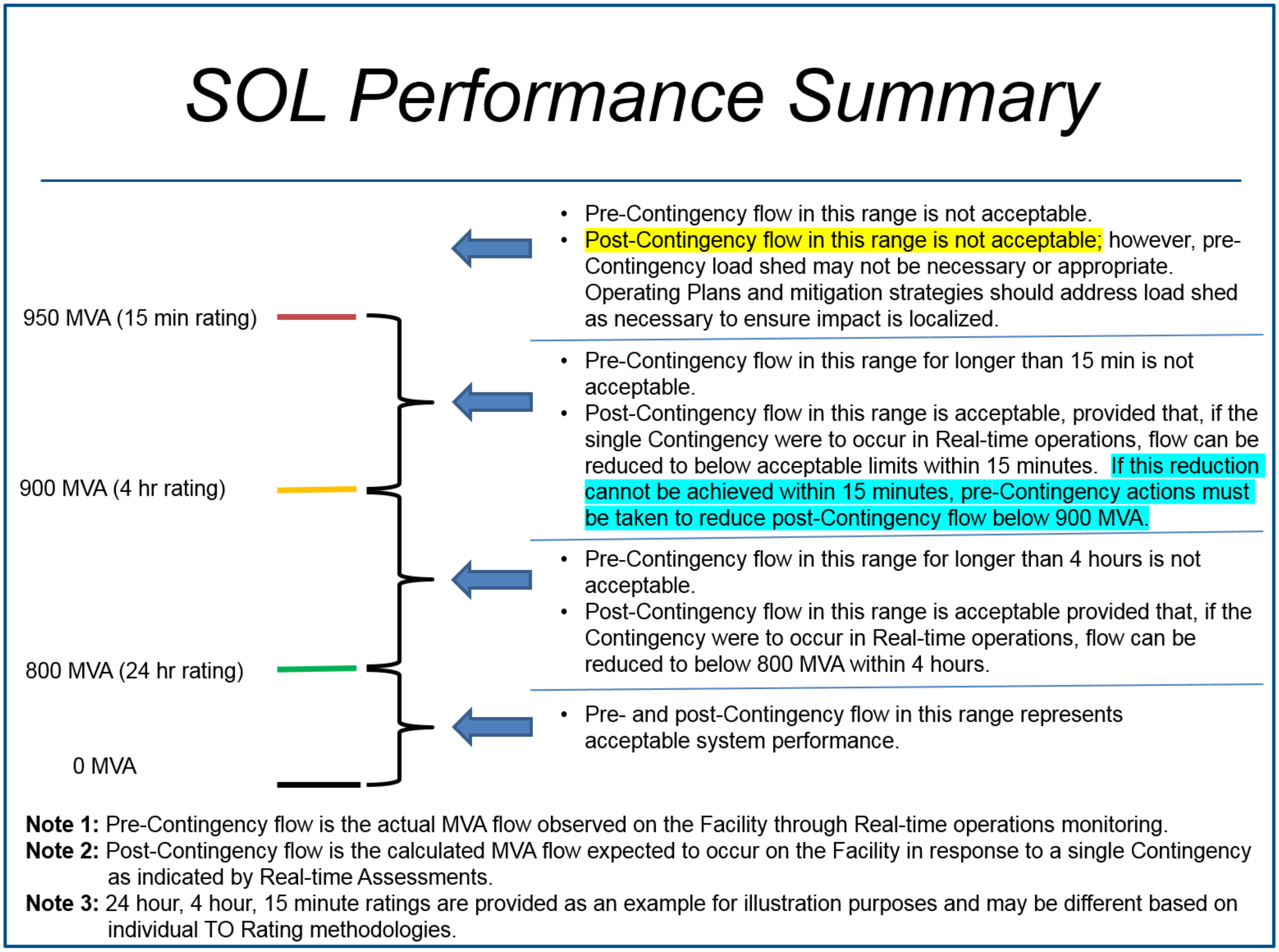
9 Emergency Ratings will always equal to or greater than the Normal Rating.

Component #7 – *The calculated post-Contingency state indicates: … Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*

The SDT concluded that the two instances contained within this item provide additional clarity that could prevent inaccurate interpretations of what it means to exceed an SOL. The intent behind this component of the definition is to reflect the concepts described in the Project 2014-03 Whitepaper with regard to Facility Rating exceedances, specifically, the two highlighted items in the diagram below. The portion of the definition that states, *"Calculated post-Contingency flow through a Facility is above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow. This operating state is considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan. In this scenario, the System Operator has no time to implement post-Contingency mitigation actions (i.e., actions that occur after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken to reduce the calculated post-Contingency flow. The portion of the definition that states, *"…or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur"* is intended to address the operating state highlighted in light blue. Again, in this scenario, the System Operator does not have adequate time to implement post-Contingency mitigation actions ; therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken to reduce the calculated post-Contingency flow. This operating state is also considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan.



Component #8 – *The calculated post-Contingency state indicates: … Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur*

The language in this component mirrors the language in the preceding bullet applicable to Facility Ratings. The same concepts described above apply. Regarding time-based System Voltage Limits, the proposed definition acknowledges that time-based System Voltage Limits are used by some TOPs and RCs. The proposed definition provides the operational flexibility for the use of time-based voltage limits in the same manner that time-based Facility Ratings are used.

As an example, a TOP could have a NORMAL System Voltage Limit of +/- 5%, an EMERGENCY System Voltage Limits of +7% and -10%, and an additional short term EMERGENCY HIGH System Voltage Limit of +10% for 15 minutes. Applying a 15 minute time value to the short term EMERGENCY HIGH System Voltage Limit of +10% could allow post-Contingency operator action to mitigate a concern as opposed to enforcing pre-Contingency action plan. In this example, a calculated post-Contingency voltage above 107% of normal but below 110% could be resolved with post-contingent action, which could be described in the Operating Plan.

<u>Component #9</u> – The calculated post-Contingency state indicates: … Defined stability performance criteria are not met

The requirements in FAC-011-4 and FAC-014-4 address the establishment of stability limits and IROLs:

1. FAC-011-4 Requirement R4, Part 4.1 requires the RC's SOL Methodology to specify the stability performance criteria that is to be used for the establishment of stability limits.
2. FAC-011-4 Requirement R4 Part 4.2 requires that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.
3. FAC-014-3 Requirement R1 requires the RC to establish IROLs in accordance with the SOL Methodology.
4. FAC-014-3 Requirement R2 requires the TOP to establish SOLs in accordance with the SOL Methodology.
5. FAC-014-3 Requirement R4 requires the RC to establish stability limits when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

The end result of these requirements is that stability limits – some of which may be IROLs – will be established in accordance with the RC's SOL Methodology. These stability limits are addressed through the third and fourth bullets in the pre-Contingency state section of the SOL Exceedance definition which state:

The pre-Contingency state indicates any of the following:

- A stability limit established to prevent instability without a Contingency is exceeded
- A stability limit established to prevent the Contingency from resulting in instability is exceeded

Accordingly, if any defined stability limit is exceeded, the third and fourth bullets in the pre-Contingency section addresses those as SOL Exceedances. These stability limits can be determined prior to Real-time, or they can be determined in Real-time through the use of Real-time stability tools. With the adoption of technology implementations, some TOPs and RCs are using stability analysis tools to calculate stability limits in Real-time using the actual system conditions as an input to the analysis. Such implementations bring a significant improvement to the accuracy of stability limits. However, regardless of when the stability limit is calculated, the above bullets apply regarding when an actual SOL Exceedance of these stability limits occurs.

However, some implementations of Real-time tools in operations, particularly transient stability tools, present a challenge to the historical paradigms of operating within established limits. For example, Real-time transient stability tools have the ability to assess actual system conditions to determine whether the system is expected to be transiently stable (or to meet certain transient performance criteria) for a set of modeled Contingencies. Real-time transient stability tools give TOPs and RCs the ability to determine in Real-time whether or not a given Contingency would result in acceptable damping or acceptable transient voltage response. When such tools are used to determine acceptable transient system performance, the tools may not calculate "an SOL" (a stability limit) in the traditional sense, i.e., the tools may not calculate a value that, if operated within, prevents the system from exceeding transient performance criteria should the critical Contingency occur (which would be monitored under the fourth bullet under the pre-Contingency section of the SOL Exceedance definition). Rather, these tools can be used in a manner to indicate when the transient performance criteria are being, or are expected to be, met.

Modern technology implementations of stability analysis tools have the ability to inform System Operators at any moment in Real-time whether the system is “stable” or whether it is “unstable” for the next Contingency event without the use of a traditional “SOL value”. For entities that use such tools as an additional mechanism to determine Real-time instability (above and beyond monitoring any defined stability limits established per the Requirements referenced in items 1-5 listed above), if defined stability performance criteria are not being met, an Operating Plan should be implemented to mitigate the condition. Such an approach represents a significant improvement in the accuracy of monitoring for acceptable stability performance in response to Contingencies; however, such an approach may not utilize an “SOL value” (a defined stability limit value) that is monitored in the traditional sense. This type of assessment, while not utlilizing a defined SOL value, does evaluate for acceptable system stability performance (i.e., post-Contingency stable operations), and as such, should be integrated into the definition. The SDT believes that operating entities should be encouraged to integrate new technologies to improve the accuracy of its reliability assessments, and that any instance of not meeting stability performance criteria as indicated by these technologies should be considered as an SOL Exceedance because it triggers the appropriate response of the implementation of an Operating Plan to mitigate the condition. It is important that the SOL Exceedance definition be “technology neutral” by addressing the techniques used to identify unacceptable stability performance in addition to the conventional or historical methods of performing studies, establishing a defined limit based on those studies, and then operating within that defined limit in Real-time.

If the TOP or RC does not utilize Real-time stability tools to determine the system’s response to Contingency events and to evaluate that response against defined stability performance criteria, but solely utilizes a more traditional approach for establishing stability limits (i.e., limit “values”) to address system instability, then the third bullet in the post-Contingency section of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance.

It should be noted that the third bullet in the post-Contingency section is going above and beyond the other components of the SOL Exceedance definition that addresses traditionally defined stability limits (the fourth bullet under the pre-Contingency section of the SOL Exceedance definition). The third bullet under the post-Contingency section is included in the definition of SOL Exceedance to enhance reliability by requiring that any operating condition characterized as “unstable” as determined by Real-time stability analysis tools is also regarded as an SOL Exceedance in order to trigger the implementation of an Operating Plan to address the condition. It important to note that TOPs and RCs that use Real-time stability analysis tools in this manner are also required to monitor any traditionally defined stability limits and to consider any exceedance of those limits under the the third and fourth bullets under the pre-Contingency section of the SOL Exceedance definition.

	DBH Notes:	1st Pass. Looking in http:
	Pending future enforcement - Orange Rows	
Does the proposed SOL definition work in the context of this standard?	**Standard**	**Requirement ID**
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Attachment 1
yes	EOP-004-3	Attachment 1
yes	EOP-004-3	Attachment 2
yes	EOP-011-1	Attachment 1
yes	FAC-008-3	Purpose
yes	FAC-013-2	R1.2

yes	FAC-501-WECC-1	R.1.
yes	FAC-501-WECC-1	Attachment 1
Incorporate SOL Exceedance definition	IRO-002-4	R3.
yes	IRO-002-4	Guidelines & Tech. Basis
Incorporate SOL Exceedance definition	IRO-002-5	R5.
Incorporate SOL Exceedance definition	IRO-006-5	Purpose
Incorporate SOL Exceedance definition	IRO-006-EAST-2	Purpose

Incorporate SOL Exceedance definition	IRO-006-EAST-2	R1.
Incorporate SOL Exceedance definition	IRO-006-TRE-1	Purpose
Incorporate SOL Exceedance definition	IRO-006-TRE-1	R1.
Incorporate SOL Exceedance definition	IRO-006-TRE-1	R2.
Incorporate SOL Exceedance definition	IRO-008-2	R1.
Incorporate SOL Exceedance definition	IRO-008-2	R2.

Incorporate SOL Exceedance definition	IRO-008-2	R5.
Incorporate SOL Exceedance definition	IRO-008-2	R6.
Incorporate SOL Exceedance definition	IRO-008-2	F. Associated Documents
yes	MOD-001-2	R1.1
Incorporate SOL Exceedance definition	MOD-028-2	R6.1.

yes	MOD-029-2a	R3.
yes	MOD-030-3	R.2.4.
yes	PER-004-2	R2.
yes	PER-005-2	Guidelines & Tech. Basis
yes	PRC-002-2	R5., R5.1 & R5.1.2
yes	PRC-002-2	Guidelines for R5
yes	PRC-004-WECC-2	R2.3.2.2.

yes	PRC-010-2	Guidelines & Tech. Basis
yes	PRC-026-1	R1.

yes	PRC-026-1	Guidelines & Tech. Basis
yes	PRC-026-1	Guidelines & Tech. Basis
Incorporate SOL Exceedance definition	TOP-001-3	R10.

Incorporate SOL Exceedance definition	TOP-001-3	R14.
Incorporate SOL Exceedance definition	TOP-001-3	R15.
yes	TOP-001-3	R18.
Incorporate SOL Exceedance definition	TOP-001-3	Guidelines & Tech. Basis
Incorporate SOL Exceedance definition	TOP-001-4	R10.
Incorporate SOL Exceedance definition	TOP-001-4	R14

Incorporate SOL Exceedance definition	TOP-001-4	R15
yes	TOP-001-4	R18.
Incorporate SOL Exceedance definition	TOP-001-4	C. Compliance
Incorporate SOL Exceedance definition	TOP-001-4	Guidelines & Tech. Basis
Incorporate SOL Exceedance definition	TOP-002-4	R1.
Incorporate SOL Exceedance definition	TOP-002-4	R2.

Incorporate SOL Exceedance definition	TOP-002-4	Guidelines & Tech. Basis
yes	VAR-001-4.1	R1.
yes	VAR-001-4.1	Guidelines & Tech. Basis
Incorporate SOL Exceedance definition	Burden	Glossary of Terms
Incorporate SOL Exceedance definition	Constrained Facility	Glossary of Terms

yes	Interconnection Reliability Operating Limit	Glossary of Terms
yes	Operations Support Personnel	Glossary of Terms
Incorporate SOL Exceedance definition	Total Flowgate Capability	Glossary of Terms

://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf for "system

Page(s)	Requirement Details
21	Bullet item under Managing Contstraints: Identify and monitor SOL's & IROL's (TOP, RC)
25	Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
28	Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
12	The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
10 of 22	Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Threshold for Reporting: Operate outside the IROL for time greater than IROL Tv (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
12	There is a checkbox for IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)
12-13	See EOP-011-1 tab
1	A Facility Rating is essential for the determination of System Operating Limits.
1	A statement that the assessment shall respect known System Operating Limits (SOLs).

1	Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled “Major WECC Transfer Paths in the Bulk Electric System.”
4	1) A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System;”
1,2, 4	Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
8 (multiple)	See IRO-002-4 tab
2	Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
1	To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
1	To coordinate action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

1	Each Reliability Coordinator that initiates the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (except TLR-1) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.[1]
1	To provide and execute transmission loading relief procedures that can be used to mitigate SOL or IROL exceedances for the purpose of maintaining reliable operation of the bulk electric system in the ERCOT Region.
1	The RC shall have procedures to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits (IROL) and System Operating Limits (SOL) that will not be resolved by the automatic actions of the ERCOT Nodal market operations system.
1	The RC shall act to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits and System Operating Limits that will not be resolved by the automatic actions of the ERCOT Nodal market operations system, in accordance with the procedures required by R1.
1, 5	Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
1, 5	Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

2, 7-8	Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Realtime Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
2-3, 9-11	Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
12	various (Same exact language is found in the Associated Documents section of IR0-008-2, IRO-014-3, TOP-001-3, TOP-002-4) See Associated Docs tab.
2-3	Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state: 1.1.1 Facility ratings; 1.1.2 System voltage limits; 1.1.3 Transient stability limits; 1.1.4 Voltage stability limits; and 1.1.5 Other System Operating Limits (SOLs).
4	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: - A System Operating Limit is reached on the Transmission Service Provider's system, or - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

3,6	Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.
3	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
1	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.
12	Rationales for R1, R2, and R5.
3	[R5.] Each Responsible Entity shall: [R5.1] Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: [R5.1.2] Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).
33	Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.
2-3	Transmission Operators shall adjust the SOL and operate the facilities within established limits.

29	Rationale for R8 - Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).
3	Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. [1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

16-17	R1 Criterion - The first criterion involves generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to the operating limit or RAS. A stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to an operating limit or RAS and do not terminate at the Transmission station associated with the generators that are subject to the SOL or RAS.
17	R1 Criterion - The second criterion involves Elements that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL. For example, if two long parallel 500 kV transmission lines have a combined SOL of 1,200 MW, and this limit is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.
4	Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

5	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
5	Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.
5-6	Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
7, 19	See TOP-001-3 tab
4-5	[R10.] Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:
5	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment

6	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
6	Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
9	Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
24	See TOP-001-4 tab
1,4	Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
1,4	Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

10	See TOP-002-4 tab
2	Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
13	See VAR-001-4.1 tab
n/a	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
n/a	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.

n/a	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
n/a	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time operations of the Bulk Electric System.
n/a	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

operating"
Corresponding Measure
n/a
n/a
n/a
n/a
n/a
n/a
n/a
n/a
n/a

n/a

Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

n/a

n/a

n/a

n/a

The RC shall provide evidence including documentation of procedures to identify and mitigate exceedances of identified IROLs and SOLs to demonstrate compliance with Requirement R1.

To demonstrate compliance with Requirement R2, the RC shall provide evidence, such as system logs, voice recordings, or operating messages that shows that it acted to identify and to mitigate exceedances of IROLs and SOLs in accordance with the procedures required by R1.

n/a

Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
o TFC or TTC being determined by one or more limits.
o Simulation being used to find the maximum TFC or TTC that remains within the limit.
o The application of a distribution factor in determining if a limit affects the TFC or TTC value.
o Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
o A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
o A statement that one or more of those limits are not applicable to the TFC or TTC determination.

n/a

Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path.

n/a

NONE

n/a

n/a

n/a

The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

n/a

Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

n/a

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.
Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence

Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded
Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.
n/a
n/a

n/a

Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

n/a

n/a

n/a

n/a

n/a

n/a

n/a

n/a

http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

VSL	Needs to be Modified?
n/a	no
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
n/a	no
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
n/a	no
n/a	no
n/a	yes - clean up (not critical)

n/a	yes - clean up (not critical)
	yes - clean up (not critical)
The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.	yes
	no
The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.	yes
n/a	yes
n/a	yes

n/a	yes
n/a	yes
The RC did not have procedures to identify and mitigate exceedances of identified IROLs and SOLs.	yes
The RC failed to follow its procedures in identifying and mitigating an exceedance of an SOL.	yes
The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).	yes
The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the nextday provided by its Transmission Operators and Balancing Authorities.	yes

Multiple levels	yes
Multiple levels	yes
	yes - clean up (not critical)
Multiple levels	no
n/a	yes - clean up (not critical)

n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
[MULTIPLE LEVELS] Reliability Coordinator operating personnel did not place particular attention on X% or less of the SOLs or IROLs or inter-tie facility limits.	no
n/a	yes - clean up (not critical)
n/a	no
n/a	no
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within X hours but did perform the requirements within Y hours.	no

n/a	no
n/a	yes - clean up (not critical)

	yes - clean up (not critical)
	yes - clean up (not critical)

n/a yes

The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment	yes
The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.	yes
The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.	no
n/a	no
n/a	yes
The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment	yes

The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.	yes
The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.	no
n/a	yes
n/a	no
The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).	yes
The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.	yes

n/a	no
References to SOLs is included in the VSLs for R2 and R3.	no
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)

n/a	no
n/a	no
n/a	yes

Modification Description
n/a
need to change the reference to the revised FAC standard and associated requirements
need to change the reference to the revised FAC standard and associated requirements
n/a
Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired on April 1. Not related to FAC SDT project. Incorporate SOL Exceedance definition elsewhere.
Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired on April 1. Not related to FAC SDT project.
n/a
n/a
Needs to remove the reference to SOLs since this requirement is applicable to PCs. Revision could reference TPL performance table.

Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired o April 1. Not related to FAC SDT project.

Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired o April 1. Not related to FAC SDT project.

Incorporate SOL Exceedance definition

n/a

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

n/a

Incorporate SOL Exceedance definition.
Not critical for these requirements.

Incorporate SOL Exceedance definition.
"The path flow that corresponds to the point of SOL Exceedance".

Incorporate SOL Exceedance definition

n/a

Incorporate SOL Exceedance definition in Reference #1: Determining Task Performance Requirements

n/a

n/a

n/a

n/a

Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.

Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.
Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.
Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

n/a

n/a

Incorporate SOL Exceedance definition
Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition
n/a
Incorporate SOL Exceedance definition
n/a

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

n/a

n/a

Rationale references current SOL definition. Need to fix based on new definition.

Incorporate SOL Exceedance definition

Incorporate SOL Exceedance definition

n/a

n/a

Incorporate SOL Exceedance definition

Notes
Not related to FAC SDT project, but it does need to be modified.
Speaks to adjustment to SOLs and/or alleviating loading on SOL/IROL. No changes required.
IF a Facility Rating is an SOL, then by default, it is essential for determining SOLs. Tis statement is not necessary in the purpose of FAC-008, but it does no harm.

Not related to FAC SDT project, but it does need to be modified.
Not related to FAC SDT project, but it does need to be modified.

While the proposed definition of SOL dos not allow for "Other SOLs" as listed in R1.1.5, this requirement does not cause a problem. It will just never be used.

The term "Burden" is used once in the body of Reliability Standards. BAL-005-0.2b requirement R3 states, *"A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas."* This standard has been replaced by BAL-005-1 which is pending regulatory approval.
The term "Constrained Facility" is not used in the current body of Reliability Standards

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: "…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific **SOL** or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific **SOL** or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible **SOL** or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those **SOLs** or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day **SOL** or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Compliance/Data Retention
Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL Tv as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

TOP-001-3 also contains the same write-up as seen in the Associated Docs tab

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by **SOLs** for clarity and specificity. **SOLs** include voltage, Stability, and thermal limits and are thus the most limiting factor.

Includes the same occurrences as TOP-001-3 plus the one below

Rationale for Requirement R10:
New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.
The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.
The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances.
Examples include:

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.
The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of **SOLs** in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.
TOP-002-4 also contains the same write-up as seen in the Associated Docs tab

Rationale for R1:
Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:
Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:
Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2015-09
Establish and Communicate System Operating Limits
Definitions of System Operating Limits (SOL) and SOL Exceedance

Informal Comment Period Open through October 30, 2017

Now Available

A 30-day informal comment period on the definitions of System Operating Limits (SOL) and SOL Exceedance is open through **8 p.m. Eastern, Monday, October 30, 2017**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments on the two revised definitions. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2015-09 Establish and Communicate System Operating Limits | SOL and SOL Exceedance Definitions

Comment Period Start Date: 9/29/2017

Comment Period End Date: 10/30/2017

Associated Ballots:

There were 36 sets of responses, including comments from approximately 92 different people from approximately 74 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to revise the current SOL definition? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need to modify the SOL definition at all.) Please explain your response.

2. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to create and implement a definition for SOL Exceedance? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need for having a definition of SOL Exceedance.) Please explain your response.

3. Considering the simplified approach to SOLs described here and the explanations provided in the definitions rationales, do you agree with the proposed SOL definition? Please explain your response and/or provide alternative language.

4. Considering the explanations provided in the definitions rationales, do you agree with the proposed SOL Exceedance definition? Please explain your response and/or provide alternative language.

5. Considering the explanations provided here and further explained in the definitions rationales, do you agree that the proposed SOL Exceedance definition should include this bullet item? Please explain your response and/or provide alternative language.

6. The SAR is being revised to authorize the SDT to review the existing body of Reliability Standards and NERC Glossary of terms, and where necessary, modify those standards and definitions to incorporate the new terms and/or definition(s) of SOL Exceedance and System Voltage Limit, as well as the revised definition of System Operating Limit. The SDT has identified the standards and terms they contend would benefit from this incorporation and has included them in separate documents with this posting for your review. Do you agree with the SDT's selections? If not, please explain your response.

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Colorado Springs Utilities	Brandon Ware	1,3,5,6		Colorado Springs Utilities	Brandon Ware	CSU	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
					Jeff Icke	Colorado Springs Utilities	5	WECC
					Hillary Dobson	Colorado Springs Utilities	3	WECC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Lucia Beal	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
New York Independent	Gregory Campoli	2		ISO/RTO Standards	Gregory Campoli	NYISO	2	NPCC
					Ben Li	IESO	2	NPCC

System Operator				Review Committee	Kathleen Goodman	ISONE	2	NPCC
					Mark Holman	PJM	2	NPCC
					Charles Yeung	SPP	2	SPP RE
					Nathan Bigbee	ERCOT	2	Texas RE
					Ali Miremadi	CAISO	2	WECC
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE and NGrid	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC

					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Ed	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed	5	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool,	Shannon Mickens	2	SPP RE	SPP Standards	Shannon Mickens	Southwest Power Pool	2	SPP RE

Inc. (RTO)				Review Group		Inc.		
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Kidwell	Empire District	1,3,5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Nathan McNeil	Midwest Energy, Inc	NA - Not Applicable	SPP RE

1. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to revise the current SOL definition? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need to modify the SOL definition at all.) Please explain your response.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed definition revision provides additional information on the determination of SOLs.	
Likes 0	
Dislikes 0	
Response	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities supports the SDT's proposal to revise the current SOL definition.	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that greater clarification will be good for the industry. BPA is in support of modifying the SOL definition as long as the SOL Exceedance Definition is also created.	
Likes 0	
Dislikes 0	
Response	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) supports the SDT’s proposal to revise the current definition of SOL and generally supports the revised definition with the exception of the use of “stability limit” within the definition of SOL. We understand from comments made during an industry webinar that this use of “stability limits” is not the same definition of “Stability Limits” used in the NERC Glossary. We believe this to be confusing to the industry. If the SDT’s use of the term does not align with the NERC glossary term, then it needs to be clearly represented for the	

industry to know and understand the difference. Additionally, the NERC SOL whitepaper also uses a variation of “Stability limit”.

Likes 0	
Dislikes 0	

Response

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	Yes
Document Name	

Comment

ITC agrees that the current System Operating Limit (SOL) definition is ambiguous. Clarifying the definition of a SOL will help to provide consistency and improve reliability.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy agrees that revising the definition of an SOL would be beneficial for the industry. Some confusion still exists as to what actually constitutes an SOL.

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak supports the need for revising the defintion of SOL and creating a new definition for SOL Exceedance. Peak believes that the SOL definition needs to be revised and that a clear definition for SOL Exceedance needs to be created and implemented in the body of the NERC Reliability Standards. Doing so would result in improved clarity and consistency and would prevent entities from adopting interpretation of SOL Exceedance that do not provide the level of reliability intended by its use in the TOP and IRO standards. Peak also believes that the key events mentioned in question #1 do not provide a sufficient basis for addressing the clarity and consistency problems associated with the current defintiion of SOL and the absence of a defintion for SOL Exceedance as described in the supporting documnet "NERC Glossary Defintions: System Operating Limit and SOL Exceedance Rationale."

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Great River Energy supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid

Answer	Yes
Document Name	

Comment

The revision is necessary to better capture industry practice and alignment with TOP/IRO standards.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy Company (MEC) supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Modifying the SOL definition is appropriate in conjunction with the addition of the definition of SOL Exceedance. Together, these definitions provide clarity and eliminate possibilities for confusion.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to create and implement a definition for SOL Exceedance? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need for having a definition of SOL Exceedance.) Please explain your response.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	

Comment

The justification for creating an SOL Exceedance definition, as described in the "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale" document, is speculative in nature. Specifically, the SDT expresses the concern that "[o]ne TOP might interpret SOL exceedances to not include the post-Contingency state when identifying SOL exceedance". However, the existing NERC definitions for OPA and RTA coupled with the requirements of the TOP-001-3 and TOP-002-4 standards logically combine to require an entity to evaluate the system for SOL exceedances for the post-Contingency condition. As such, there is insufficient reasoning to create a new definition for SOL Exceedance.

The SDT's concern appears to be with the wording of TOP-001-3 R14. Although ATC believes that there is no conflict or gap, a SAR could be written to improve the TOP-001-3 R14 requirement if the SDT still believes that there is an issue with the language.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

We do not believe it is necessary that NERC define SOL Exceedance. Operating outside an SOL in Real-time is an exceedance of the limits. An SOL that is predicted to be exceeded using RTA and OPS is a predicted exceedance, or a potential exceedance, but until it actually happens, it is not an exceedance. We believe it is important to keep a Real-time exceedance and an exceedance predicted by RTA or OPA separate from each other.

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment	
CenterPoint Energy does not support the creation and implementation of a definition for SOL Exceedance. We believe that the proposed term SOL Exceedance could potentially confuse the industry and take away from the clarity provided to the industry with the proposed revisions of the SOL definition. Furthermore, we believe that the proposed revisions to the definition of System Operating Limit (SOL) provide the industry with a clear and concise definition of the term; therefore, the industry understands that an exceedance to an SOL is when the applicable electrical values have gone beyond those established Facility Ratings limits, System Voltage Limits, and stability limits used in the operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
The addition of the definition of SOL Exceedance is necessary in conjunction with the modification of the definition of SOL.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
See our comments under Question 7.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	

Comment	
MidAmerican Energy Company (MEC) supports the SDT's proposal to create a definition of SOL exceedance, as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Great River Energy supports the SDT's proposal to create a definition of SOL exceedance. However, the definition should not result in unintended consequences of imposing additional and undesirable administrative compliance burden to the detriment of system reliability. Additional administrative burden in an operational setting detracts from the reliable operation of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	

Comment

Peak supports the need for revising the defintion of SOL and creating a new defintiion for SOL Exceedance. Peak believes that the SOL defintion needs to be revised and that a clear definition for SOL Exceedance needs to be created and implemented in the body of the NERC Reliability Standards. Doing so would result in improved clarity and consistency and would prevent entities from adopting interpretations of SOL Exceedance that do not provide the level of reliability intended by its use in the TOP and IRO standards. Peak also believes that the key events mentioned in question #2 do not provide a sufficient basis for addressing the clarity and consistency problems associated with the current definition of SOL and the absence of a defintion for SOL Exceedance as described in the supporting document "NERC Glossary Defintiions: System Operating Limit and SOL Exceedance Rationale."

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy agrees that a definition of SOL Exceedance would be advantageous to the industry.

Likes 0	
Dislikes 0	

Response

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF

Answer	Yes
Document Name	

Comment

ITC believes that defining SOL Exceedance will help to provide consistency and improve reliability.

Likes 0	
Dislikes 0	

Response

Theresa Allard - Minnkota Power Cooperative Inc. - 1

Answer	Yes

Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes the revision to the definition of SOL cannot occur unless SOL Exceedance is added to the Glossary.	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe supports the SDT's proposal to create a definition of SOL exceedance, **as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities**. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations.	
Likes 0	
Dislikes 0	
Response	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	

Comment	
Colorado Springs Utilities agrees that a definition for SOL Exceedance would provide needed clarity in the various affected Standards.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
There has been ongoing confusion of whether SOLs are limits or are violations. The proposed definition provides clarity for the distinction.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Considering the simplified approach to SOLs described here and the explanations provided in the definitions rationales, do you agree with the proposed SOL definition? Please explain your response and/or provide alternative language.

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	
While very close, it is felt that a tweak to the language can provide clarity in how RTM, RTAs, and OPAs are performed. Consider using: “Facility Ratings, System Voltage Limits, and stability limits **more restrictive than Facility Ratings (including margins if required)** used in the operation of the BES.” This ensures that RTAs and OPAs are not checked against Facility Ratings and then separately stability limits; it should only be the more limiting of the two. Other “studies” are still required to verify if stability limits are more restrictive, but are not needed as part of the RTAs and OPAs.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
ITC agrees that the proposed SOL definition provides clarity and removes ambiguity. However, because the term "System Voltage Limit" is included in the definition of SOL, the definition of "System Voltage Limit" should be considered in this comment form. Assuming the definition of "System Voltage Limit" stands as currently proposed, ITC would approve of the proposed SOL definition.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
See our comments under Question 7.	
Likes 0	

Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	

Comment

Comments: ATC has three comments with the proposed SOL definition:

1. The existing SOL definition contains important language regarding the "applicab[ility]" of the limit used. This clarity is missing from the proposed SOL definition revision. ATC believes the existing definition is better than the proposed definition from this perspective although entities could read “applicable” into the proposed definition as needed.
2. The term SOL is not used in proposed standard FAC-015-1 for the planning horizon. However, the concept does exist in the proposed standard. The proposed SOL definition only calls out the operating horizon and would be improved by recognizing the planning horizon as well. ATC recommends that the proposed SOL definition be edited to address this omission with wording like, “. . . used in the operation and planning of the BES”.
3. Similar to ATC’s response to Question #5 (below), stability limits can be a difficult to understand term to use in the SOL definition, especially since it is undefined. The SOL Exceedance definition tries to aid entities that establish and monitor SOLs by including the terms “stability performance criteria” to cover a wider range of system phenomenon than traditional stability limits (e.g., voltage stability, angular stability, system stability). For question #5, ATC recommends the use of “system performance criteria” to recognize that the underlying issue may not be a traditional stability problem but some other important system performance limit that is being exceeded. The underlying system issue is then represented by a proxy “stability limit” to keep the system within the bounds of acceptable performance. It would seem that this type of clarification would be more reasonably provided in the SOL definition and not the SOL Exceedance definition. Alternatively, the SDT could create a “Stability Limit” definition, which would then be referenced in the SOL definition by using the capitalized term. If a Stability Limit definition is created, the definition would then need to clearly indicate that both traditional stability issues and other system performance criteria issues (such as voltage ride through curves, angle difference from system reference angle, margin from voltage collapse point, system damping attenuation, etc.) can be represented with Stability Limits.

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

The proposed definition provides needed clarity.

Likes 0	
Dislikes 0	

Response	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities finds the revised definition of SOL acceptable and workable.	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoen agrees with the definition of SOL proposed by SDT.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA’s interpretation of a stability limit is often associated with a path.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the SDT's proposed revision of the SOL defintion and with the arguments set forth in question #3 and with those set forth in the supporting document, "NERC Glossary Defintioins: System Operating Limit and SOL Exceedance Rationale."	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
We agree with the proposed definition, but in practice in order to remain within SOLs in operations is often the use of pre-determined transfer and monitoring of specific interfaces (either thermal, voltage stability, or transient stability). The concept is introduced in the rationale for component #5 and #6 of SOL exceedance, but more rationale regarding how a transfer interface is managed versus the simplified SOL definition would be helpful. Also, the use of "lower case" stability limits rather than the defined term causes some confusion. Why use the defined term for FR and SVL, but not stability limits? What is a stability limit for the purpose of the SOL definition?	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy Company (MEC) agrees with the definition of SOL proposed by SDT.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation supports categorizing all Facility Ratings, System Voltage Limits, and stability limits as SOLs.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Considering the explanations provided in the definitions rationales, do you agree with the proposed SOL Exceedance definition? Please explain your response and/or provide alternative language.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	

Comment

The proposed SOL Exceedance definition is unworkable as written.

The definition has a fundamental flaw as it is attempting to create a one size fits all definition for two very different situations. The two situations are: (1) real-time situations (Real-time Monitoring and Real-time Assessments), and (2) static situations (Operational Planning Analysis). As categories of these situations imply, there are different time components associated with an SOL Exceedance in each situation that are not adequately addressed by the proposed SOL Exceedance definition.

There are three primary concerns with the definition as written and applied towards real-time situations: (1) the pre-Contingency language, (2) the post-Contingency language, and (3) purpose of the definition.

1. The pre-Contingency portion of the definition is not workable because it assumes a static system and does not account for timeframes associated with operating to various SOLs in real-time situations. Specifically, the first two bullets require the use of a "Facility's Normal Rating" and "normal System Voltage Limits", which are not applicable to a system that has just suffered a contingency. As recognized in the post-Contingency language, once a contingency has occurred the actual flow on the system may exceed the Normal Rating and/or the actual voltage may be outside of normal System Voltage Limits. Prior to the contingency occurring, this was not an SOL Exceedance but now that the contingency has occurred it shall be deemed an SOL Exceedance solely because of the definition's pre-Contingency language. The definition does not recognize that the new pre-Contingency state has flows below the "Facility's highest Emergency Rating" but above the Normal Rating. This condition is not an SOL Exceedance because the system is operating as designed and is not experiencing unacceptable system performance. Flows will be able to be returned below the Normal Rating within the applicable timeframe. The TOP should not have to deem this an SOL Exceedance because the SOL has not been exceeded.
2. The post-Contingency portion of the definition is not workable because is assumes a static system whereas there are constantly changing real-time inputs of a possible post-Contingency state. Assessing the post-Contingency state represents only a snapshot in time. However, due to the way contingency analysis tools work, it can be several minutes before another snapshot of the real-time inputs calculates the newly expected post-Contingency state. The definition means an entity has an SOL Exceedance for even a single post-Contingency state result, which may not be valid due to the fluidity of the system, especially in a market. Given the way the STD is intending to use the definition (i.e. as a driver of action to mitigate the issue), the post-Contingency language would need to include reference to a **persistent** post-Contingency state indication.
3. The SDT explains that the purpose of this definition is to drive an action, which is not the purpose of a definition. As stated in the rationale document (p. 9), the SDT believes the proposed definition "accomplishes the intended reliability objective of triggering an appropriate action". NERC definitions should not drive requirements for entities. Rather, this function is accomplished by the requirements within the NERC Standards. A proposed definition should define what an SOL Exceedance is or is not. The proposed definition does not create this level of clarity because the SDT has developed a definition with a particular required action in mind (e.g., see above regarding the "pre-Contingent state" language). A proposal for edits to the definition is given below and these proposed edits will achieve the intended outcome the SDT desires because the edits recognize the time-based nature of limits, which the SDT recognizes in its rationale document (cf. p. 11).

ATC recommends that the SOL Exceedance definition not be created. However, if the definition will be created, ATC recommends that the two separate definitions be created to recognize the difference between real-time and next contingency situations regarding SOL exceedances. If two definitions will not be created, at a minimum, edits must be made to the "pre-Contingency state" language so that the definition does not reference "normal" ratings or voltage limits. This specific language should be changed to refer to "applicable" ratings and "applicable" voltage limits because of the explanation above regarding the definition applying to real-time situations immediately following a contingency (i.e. what was not an SOL exceedance suddenly becomes an SOL exceedance, which is not logical from a definition standpoint).

Proposed definitions for SOL Exceedance in both RTA and OPA would bring clarity to the industry. The proposed definitions are as follows:

SOL Exceedance - Real-time:

An Operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring or Real-time Assessments (RTA):

The pre-Contingency state indicates any of the following:

- Actual flow through a Facility is above the Facility's applicable Rating for a time period longer than deemed acceptable.
- Actual bus voltage is outages applicable System Voltage Limits" for a time period longer than deemed acceptable.
- A stability limit established to prevent instability without a Contingency is exceeded for a time period longer than deemed acceptable.
- A stability limit established to prevent the Contingency from resulting in instability is exceeded for a time period longer than deemed acceptable.

The calculated post-Contingency state indication persists for any of the following:

- Flow through a Facility is above the Facility’s highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur
- Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur
- Defined stability performance criteria are not met

SOL Exceedance - Next Contingency

An Operating condition or analysis result characterized by any of the following, as determined in Operational Planning Analysis (OPA):

The pre-Contingency state indicates any of the following:

- Flow through a Facility is above the Facility's normal Rating
- Bus voltage is outages normal System Voltage Limits
- A stability limit established to prevent instability without a Contingency is exceeded
- A stability limit established to prevent the Contingency from resulting in instability is exceeded

The calculated post-Contingency state indication persists for any of the following:

- Flow through a Facility is above the Facility’s highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur
- Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur
- Defined stability performance criteria are not met"

These changes will allow the definition to work in the pre-Contingency state as envisioned by the SDT while also clarifying that an SOL exceedance after a contingency occurs in real time only exists if the actual flow or the actual voltage (i.e. the new pre-Contingency state) is outside of the applicable limit for an applicable period of time. In addition, these changes provide the needed clarity for post-Contingency situations.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	

See our comments under Question 7.

Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	
Comment	

NIPSCO is not in agreement that an SOL Exceedance has occurred if the flow is over a rating for an “Acceptable duration” being the time allowed for the next emergency rating. We do agree that an exceedance would occur if outside that “acceptable duration”. In the explanation the Standards Develop Team states that “any PERSISTENT exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an acceptable duration.” The word “persistent” and the idea that there is NOT an “acceptable duration” for the flow to go over the Normal Rating seem to contradict. Also the SOL Performance Summary on page 11 of the Rationale document states, “Pre-Contingency flow in this range (between normal and first emergency) for longer than 4 hours is not acceptable.” How does this fit the explanation? Is 4 hours the acceptable duration? And if it is not acceptable to go beyond the 4 hours then we assume less than 4 hours is acceptable. If so, how can an SOL exceedance be acceptable since by the SDT definition for a flow above normal there is an SOL exceedance? We believe the MISO definition for Pre-Contingency as it relates to Facility Ratings is better. The MISO definition is as follows:

SOL Exceedance Based on Real-Time Flows

A. Actual steady state flow on a BES Facility is greater than the Facility’s highest Emergency Rating for any time period.

B. Actual steady state flow on a BES Facility is above the Normal Rating, but below the next Emergency Rating, for longer than the time frame of the next Emergency Rating.

C. Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

D. Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

E. Any established stability Limit (non-IROL) is exceeded for longer than the 30 minutes or defined by operating guides.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	

MidAmerican Energy Company (MEC) re-iterates our disagreement with the proposed definition of SOL exceedance. We note the SDT's reluctance to incorporate our original comments and suggested changes submitted during the August 2016 commenting period.

- The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause unintended consequences on large spectrum of the Industry's participants.
- The first issue with the SDT's proposed definition of the SOL exceedance is that it would expose TOPs and RCs to unnecessary compliance risk. Significant resources for each TOP's/RC's organization would be required to meet the higher compliance administrative burden.
- The second issue is the definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, MEC believes the definition could delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. MEC believes that a potential unintended outcome to avoid the administrative burden would be to operate in an unnecessarily conservative operation mode**.** The SDT has downplayed existing NERC standards that already currently require system operator training, tools, and processes to trigger the implementation of Operating Plans, including SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while respecting existing limitations of existing transmission infrastructure and human resources that operate this infrastructure. In other words the *SOL exceedance definition should be focused on defining what is considered to be unacceptable operation rather than what should be good operating practice based recommendable operation*.

Therefore, MEC recommends the SDT defer voting/ballots on this item until such time that the following tasks are completed:

- Perform comparative analysis of existing SOL definitions nation-wide, in order to get an informed insight as to where majority of industry's participants stand on this definition.
- Perform analysis of additional staffing resources and tools that would be needed to implement proposed definition.
- Outline and assess compliance driven administrative burden that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.
- Evaluate a risk of overwhelming and distracting real-time operations people with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.
- Assess the potential impact of outages with the implementation of the proposed SOL definition. The combination of the proposed SOL definition and operational outages could significantly constrain business in the industry associated with the industry's inability to approve and perform numerous scheduled outages (with many of them mandated by other NERC standards). The conservative definition of SOL exceedance would simply make it impossible for many of these outages to proceed without causing SOL exceedances.

- Assess the impact that the proposed definition would have on efficiency of market operations and associated cost.

MEC *recommends the SDT reconsider adoption of the current SOL exceedance in effect in the MISO Reliability footprint*. This is based on the following advantages of the MISO definition when compared with the SDT's proposed definition. The MISO definition:

- *Is more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
- *Would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
- Would provide *comparably reliable operation* of power systems.
- Is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".
- Would *prevent potential increased* market operations costs.
- Would provide *more clarity and avoid ambiguity and interpretation issues*.
- Is more efficient for small entities that don't have advanced tools and other resources, including, but not limited to staffing and support personnel.

The current MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

- *Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.*
- *Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.*
- *Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.*
- *Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.*
- *Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.*
- *Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*
- *Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*
- *Rationale for MEC Comments and Recommendation*
- The SDT limited its vision of this subject to the Project 2014-03 Whitepaper. The Whitepaper was product of a small subset of subject matter experts. The original version of the NERC White Paper (from May 2014) was more objective and referenced the use of post-contingent action plans to address projected post-contingent issues. Subsequent versions of the NERC White Paper (revision of January 2015) weren't presented to industry, weren't approved by the Industry. More industry participant input responsible for implementing the real-time SOL exceedance definition is still needed.
- The SDT proposed definition of the SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance. This attempt to include both of them under the single, generic term

“SOL exceedance” may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar. The actual, pre-contingency SOL Exceedance is a real-time condition exceeding the equipment’s rated capabilities, while the calculated, post-contingency risk of SOL Exceedance requires another event to happen in order to become real and actual exceedance issue.

- Both pre-contingent and post-contingent types of exceedances require and should trigger implementation of a control action from the Operating Plan. However, implementation should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability.

MEC comments on specific “components” from the SDT’s document:

Component #3 – *The pre -Contingency state indicates: … Actual flow th its* **Normal Ratin**

- Persistent should be removed as ambiguous and not auditable. The SDT determined that any persistent exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an acceptable duration. MEC disagrees with the SDT’s insistence on using Normal Rating and recommend the use of Emergency Rating. The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses *no reliability repercussions as long as the flow on facility is returned below normal rating during time that was assigned for the emergency rating*. Transmission operators have used emergency ratings for many years and that fact should be correspondingly recognized in the SOL exceedance definition.

- The SDT’s rationale to use Normal Rating in order to “trigger implementation of Operating Plan” is confusing. TOPs understand the limitations associated with the use of Emergency Rating and their obligation to return the flow below Normal Rating within specified time-frame. Hard-coded SCADA based operational alarms will trigger implementation of Operating Plan. Therefore, it is unnecessary to adopt a conservative definition of SOL exeedance in order to “remind” TOPs and RCs of their well understood obligation to return flow under Normal Rating in specified time-frame.

- Although the SDT stated that the their goal is to improve clarity and eliminate ambiguity they increase ambiguity and open another issue of interpretation by introducing the term **“**persistent exceedance of a Normal Rating”. The time of exceedance has to be clearly specified in this component. Otherwise, how will entities, including Auditors, measure “persistency” of exceedance?

- The proposed, conservative definition could cause undesirable consequences in terms of administrative compliance burden and an unnecessarily increase the cost of market operations while providing marginal benefit to system reliability. TOPs/RCs are already under NERC obligation to protect facilities on a contingency basis, which will consequently protect that facility against real-time flow exceedances.

MEC recommends the following definition superior alternative:

- ***Actual steady state flow on a BES Facility is greater than the Facility’s highest Emergency Rating for any time period.***

- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Component #4 – *The pre -Contingency state indicates: Actual bus voltage is outside normal System Voltage Limits*

- MEC disagrees with the SDT’s insistence on using Normal System Voltage Limits and recommend using Emergency Voltage Limits. Our arguments regarding the Component #4 are similar to our comments concerning the Component #3.

- The technical rationale for our recommendation is based on the fact that TOPs/RCs do operate their systems within normal voltage limits during vast majority of the time. However, there are rare instances when sudden events and changes to operating conditions, or periods during switching long transmission lines, require use of emergency voltage limits. That is why *SOL exceedance definition should be focused on what is* *considered to be unacceptable operation rather than what should be recommended operation*. Again, the proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden.

MEC recommends the following definition:

- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

Component #6 – *The pre Contingency established to prevent the ··· A stability li*

Contingency from resulting in instability is exceeded

- The SDT differentiated between stability limits occurring without contingency and stability limits that are contingency based and conditioned. The SDT rational doesn't justify the existence of two components related to stability limits.
- The physical nature of the stability limits is best addressed within individual Operating Plans. Therefore, there is no need to separate the different natures of stability problems within the definition of a SOL exceedance. This is an unnecessary complication and could be resolved by merging two subcomponents into the one.
- The proposed definition does not recognize time-frame associated with exceedances of established stability limits. If not recognized this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%).

We recommend the following definition:

- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***

Component #7 – *The calculated post or Contin above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*

- The SDT provided clarification of their position by pointing out the (Project 2014 e03 White paper) two diagram. The portion highlighted in yellow, according to the SDT's explanation) " is considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan".
- Please note the original version of the NERC White Paper (from May 2014) stated that "Post-contingency flow in this range is not acceptable unless Operating Plan address reliability impact so that it has localized impact". Subsequent versions of the NERC White Paper (revision of January 2015) introduced a statement that "Post-contingency flow in this range is not acceptable". This revision wasn't presented to the industry, and never approved by the Industry.
- The SDT's proposed definition of the post-Contingency flow SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar.
- Both types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated

differently in terms of urgency and severity of mitigating control actions, as they have different repercussions on system reliability.

- The portion of the definition that states, *"…or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur"* is intended to address the operating state highlighted in light blue. This portion of the definition will cause industry implementation and compliance issues. It introduces ambiguity and confusion. Because TOPs/RCs would be faced with hard and sometimes impossible task to determine what is actually "sufficient time" for any specific set of operational circumstances. This time may depend on unit ramp rates along with efficiency and speed of congestion management procedures (such as LMP binding). This could impose significant market operations costs, while providing marginal reliability benefits.

MEC recommends the following definition:

- *Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*

Rationale for using Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the concept of post-contingent action plan. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating.* It's important to note that the Post-contingency action plans are NOT a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

- MEC recommends a Post-contingency action plan developed by the TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

- Therefore, MEC would not consider a SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes without associated post-contingency action plan.

- MEC recognizes that there may be situations when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this fashion and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

The SDT's concept insists on the concept "highest Emergency Rating". The MEC alternative definition is based on the concept of "post-contingency action plan". MEC recognizes it might be argued that the TOP has to establish a new Short Emergency rating in contrast to agreeing with its RC on post-contingency action plan. Issuing a new Short Term Emergency rating should be considered as a legitimate alternative. However, there are practical obstacles to issuing higher emergency ratings (or "Load Shed Rating"). The Industry must obtain manufacturer confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment (breakers, switches, wave traps, CTs conductors, all transformers components etc). The majority of manufacturers aren't willing to provide such data. Therefore, for practical reasons, short-term ratings based on manufacturers' data are difficult to corroborate. Consequently, each TOP and RC would need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team removes the term "Operational Planning Analysis (OPA)" from the SOL Exceedance definition. From our perspective, we feel that the SOL Exceedance Definition should be applicable to only an actual SOL Exceedance instead of focusing on a potential exceedance.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	
IRC is concerned that the use of the term "acceptable levels" in the first and second bullets under the description of the "calculated post-Contingency state" is unclear as to which entity—the responsible entity or the compliance authority—determines what level is "acceptable." Although the IRC believes the responsible entity should be the entity that determines the appropriate level, IRC has no consensus on appropriate substitute language at this time.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	

Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Great River Energy does not agree with the proposed definition of SOL exceedance for the following reasons.

- The SDT's proposed definition of the SOL exceedance would expose a large number of operating entities, both TOPs and RCs, to increased compliance risk through additional administrative burden with no foreseen benefit to reliability.

- The definition should allow for a maximum time the limit can be violated, similar to the approach currently in place with Interconnection Reliability Operating Limits. This would allow time for the execution of responses either through automated mechanisms or System Operator actions to mitigate the system condition. NERC currently defines Emergency Rating as a limit, which can be exceeded for a finite period, as specified for a facility by its equipment owner. Current practices leverage the use of Emergency Ratings in many operation and planning activities, and shifting to a more stringent definition could create a significant compliance burden.

The proposed definition fails to consider the validity of calculated post-contingent values. Applicable entities will soon be held accountable with the quality of developing Real-time Assessments, as required in NERC Reliability Standards IRO-018-1(i) and TOP-010-1(i). These assessments help identify real actions that must be implemented in order to alleviate potential system problems. Often these problems are identified through N-1 contingencies, although could be identified through multiple level "tower" contingencies accounting for Facilities that are located on the same transmission infrastructure. Violating limits associated with these limits, while concerning, may not pose an immediate threat to system reliability. The definition should narrow the exceedance identification process to only real, pre-contingent values.

- We suggest and recommend *that SDT consider adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint*, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:

- It is much more realistic in recognizing existing transmission infrastructure and human resources allocated to operate such an infrastructure

- It would provide for significantly less administrative compliance burden on numerous Industry's entities as related to providing evidence to meet the current definition.

- It would provide comparable reliability in the operation of the transmission system with a substantial benefit of less administrative burden.

- It is based on the physical limitations of various components of transmission facilities as opposed to being based on "intention to trigger implementation of Operating Plan".

- It provides more clarity and avoids ambiguity and interpretation issues.

- It is much more acceptable to vast majority of Industry participants, especially smaller TOPs

As a reference to the SDT, a MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following seven conditions:

- Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.
-
- Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of

the next Emergency Rating.

- Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.
- Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.
- Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.
- Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.
- Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.
- Great River Energy would like to emphasize the difference between the above definition and the SDT's proposed definition as it relates to the concept of a post-contingent action plan. The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used while the normal congestion management processes are attempting to return the projected post contingent flow within a longer-term rating for a specified amount of time. An SOL exceedance should not exist if a post contingent action plan has been identified and is in place to address the contingency were it to occur. It should only exist if no plan has been formulated within the specified time frame which for MISO members has been identified as 30 minutes.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

We do not believe it is necessary that NERC define SOL Exceedance. However, if there is going to be a definition we believe a simple definition for Real-time operations is best.

We suggest the following definition:

SOL Exceedance - An operating condition, as determined in Real -time Monitoring, wher

An exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. Predicted exceedances, such as those identified through OPAs and RTAs, may or may not occur as they are just that, predicted. Predicted exceedances should not be defined and subject to the stringent set of limitations and requirements that SOL Exceedances should be. Furthermore, how predicted exceedances are identified, assessed, operationally planned for and mitigated should be the responsibility of the Reliability

Coordinator. Therefore, any such definition for predicted exceedances should remain in the respective RC's SOL methodology.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. We believe the definition should allow for a maximum time the limit can be violated, similar to the approach currently in place with Interconnection Reliability Operating Limits. This would allow time for the execution of mitigative responses either through automated mechanisms or System Operator actions. NERC currently defines Emergency Rating as a limit, which can be exceeded for a finite period, as specified for a facility by its equipment owner. Current practices leverage the use of Emergency Ratings in many operation and planning activities, and shifting to a more stringent definition could create a significant compliance burden.
2. We believe the proposed definition fails to consider the validity of calculated post-contingent values. Applicable entities will soon be held accountable with the quality of developing Real-time Assessments, as required in NERC Reliability Standards IRO-018-1(i) and TOP-010-1(i). These assessments help identify real actions that must be implemented in order to alleviate potential system problems. Often these problems are identified through N-1 contingencies, although they could be identified through multiple level "tower" contingencies accounting for Facilities that are located on the same transmission infrastructure. Violating limits associated with these limits, while concerning, may not pose an immediate threat to system reliability. The definition should narrow the exceedance identification process to only real, pre-contingent values.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance

Answer	No
Document Name	

Comment

Entergy strongly disagrees with the definition as written.

The "pre-Contingency" state does not include a statement regarding time. If an entity using time dependent emergency ratings it should only be an exceedance if the actual flow through a facility is above the Facility's normal rating for a period of time greater than the timeframe of the emergency rating. The definition of the post-contingency state does take into account emergency ratings but they are essentially useless if by definition the instance after the contingency occurs and now you move into the next pre-contingency state you will immediately have an SOL exceedance.

In addition, the post-contingency state mentions the term "sufficient time" but doesn't describe what "sufficient time" time is. This leaves the definition ambiguous.

Entergy believes you should adopt the MISO definition of SOL exceedance as follow.

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***
- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***
- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***
- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***
- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***
- ***Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to
"Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded."

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment	
Duke Energy requests further clarification on the rationale behind the differences in criteria between pre-Contingency, and post-Contingency. As proposed, 'pre-Contingency' criteria for exceedances are above 'normal' ratings/limits, whereas 'post-Contingency' criteria for exceedances being 'above the highest/lowest' rating/limit. We feel that the rating/limit should be the same for both, and propose that the pre-Contingency criteria should also be for 'above the highest/lowest' rating/limit. Some ambiguity exists with the use of "Normal Rating". It is possible that an entity could interpret the use of "Normal Rating" to include all ratings. We recommend the drafting team consider adding language that explains that a "Normal Rating" is defined by the entity's SOL Methodology. • *"Actual flow through a Facility is above the Facility's Normal Rating (as defined by entity's SOL Methodolgy)"* Also, there appears to be some inconsistency between the text of the SOL Exceedance definition, and the SOL Performance Summary table found on page 11 of the SOL/SOL Exceedance Rationales document. The table implies that an SOL Exceedance can occur within the 1-hr rating range. Was this the drafting team's intent? It is acknowledged that action is needed if the Exceedance occurs within the 1-hr ratings range, but does the drafting team contend that an SOL Exceedance can occur even if you are still in that 1-hr rating. Lastly, The definition does not address temporary conditions. What happens if you have a fault and it drags your bus voltage down long enough to pick up and alarm, and then restores. Would that be a exceedance according to the proposed definition? We recommend that the drafting team include language that outlines how long an SOL may be exceeded in the RTA before a Mitigation Plan should be developed. We suggest that the drafting team insert language recommending that an SOL Exceedance has not occurred until the SOL has been exceeded for a period of 30 minutes or longer.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
The proposed definition of SOL Exceedance does not consider the concept of timeframes on Facility Ratings. Specifically, the SOL Performance Summary on page 5 of the System Operating Limit Definition and Exceedance Clarification whitepaper from Project 2014-03 indicates that Pre-Contingency flow between a Normal Rating (24 hour rating) and a higher Emergency Rating with an associated timeframe (4 hour in the specific example) is not an SOL exceedance until flow exceeds both the Normal Rating (24 hour rating) and the time limit associated with the higher limit (again, 4 hours in this specific example). The proposed definition of SOL Exceedance would consider Pre-Contingency flow above the Normal Rating (24 hour rating) to be an SOL Exceedance irrespective of any time based higher rating. For the Pre-Contingency state, actual flow through a Facility above its Normal Rating should not be an SOL Exceedance unless the actual flow through the Facility stayed above the Normal Rating for a duration longer than the timeframe associated with the next rating. NERC standard TOP-001-3 R14 states that "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment". Per the definition of SOL Exceedance TOP's will be required to mitigate flows going above normal rating all of the time even if the facility has a valid higher rating that allows flows to be above Normal Rating for a defined period of time. While the system operators will act to reduce flows to below the normal rating an SOL Exceedance should not be defined to occur until the defined period of time for the next higher rating has been exceeded. Defining an SOL Exceedance to occur whenever the normal rating is exceeded regardless of timeframe creates a compliance burden on real time operations staff that will reduce reliability due to the distractions associated with creating compliance documentation.	

For the post-Contingency state, it should be made clear that monitoring Normal Ratings for contingency analysis is not required. Instead, as depicted in the SOL Performance Summary on page 5 of the System Operating Limit Definition and Exceedance Clarification whitepaper and on page 11 of the NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale document, having a long term Emergency Rating of sufficient duration to allow for a reduction in flow to below the Normal Rating would allow for monitoring to Emergency Ratings during contingency analysis. Requiring TOP's to monitor contingency analysis results for post contingent conditions that exceed Normal Ratings will create undue burden on system operators as well as on the contingency analysis programs. In addition, setting the threshold lower than what is currently used may reduce the usage of the transmission system. Due to the significant increase in the volume of reported contingency violations which will need to be sorted through and contemplated. In fact, some contingency analysis tools have a finite number of contingency violations that can be reported and depending on the relative severity of contingent violations, will likely result in not reporting valid post-contingent violations of emergency limits which have a much more significant impact on reliability.

Often times load shed is used as a mitigation plan when flow on a facility is above the highest Emergency Rating however implementing pre-contingent load shed to mitigate an SOL Exceedance may not be prudent all of the time since load shed may occur when the contingency happens. In addition, the impact of SOL Exceedance is local in nature. A TOP should have the ability to weigh the risks/benefits associated with implementing load shed vs risking a localized impact for a postulated post-contingent condition without having to factor in SOL Exceedance compliance considerations. The transmission system is much too dynamic to be overly prescriptive. Specifically, with the proposed definition of SOL Exceedance, standard TOP-001-3 R14/R15 may not explicitly allow for TOP's to not implement pre-contingent load shed if post contingent operation is above the highest Emergency Rating. The Project 2014-03 Whitepaper clearly specified that pre contingency load shed may not be necessary or appropriate. Absent any modifications to TOP-001-3 the proposed SOL Exceedance definition may require pre-contingent load shed actions. If the definition is used as currently proposed then TOP-001-3 should also be revised to add clarification that a post contingent SOL Exceedance is acceptable as long TOP has a viable Operating Plan.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1,3,5,6

Answer	No
Document Name	

Comment

Manitoba Hydro agrees with the SDT that a definition for SOL Exceedance is needed to support the updated standards. We agree with all components of the definition with the exception of components #3 and #4 – exceeding normal facility ratings or normal voltage limits. Should exceeding the normal facility rating or normal voltage be the trigger for all the reporting requirements included in these updated standards. Most TOPs can exceed their normal facility ratings and normal voltage limits without any adverse effects on the system. In fact, these TOPs have emergency facility ratings and emergency voltage limits to give operators the time to take corrective actions in response to an event that would cause these normal ratings and limits to be exceeded. It seems unnecessarily burdensome to ask TOPs and RCs to report and document these events when they pose no risk to reliability. Conversely, exceeding emergency ratings and limits is definitely impactful to the reliability of the BES. It is appropriate to expect a higher threshold of reporting and documentation for these events.

With the proposed definition, SDT putting a huge compliance burden on to TOPs and RCs for no apparent reliability impact. New definition require TOP to notify their RC, every time the real time flow or the voltage goes outside the normal range and make a log entry for compliance purposes.

Manitoba Hydro believes that the SOL Exceedance definition should reflect the more sever conditions than the normal rating. For an example, due to absence of NERC definition for SOL Exceedance, MISO members developed definition for the SOL Exceedance. Like the proposed NERC definition, MISO SOL Exceedance definition also covers the real-time condition and the projected post contingency condition. According to MISO definition, SOL exceedance occurs whenever the real-time flow goes above the highest Emergency rating or the real-time voltage goes outside the emergency voltage

limits. Manitoba Hydro support MISO's approach of managing SOL exceedance.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not agree with the proposed definition of SOL Exceedance and believes that a definition is not necessary. If you take into consideration the FERC-referenced, NERC SOL Whitepaper coupled with the work the SDT has done to provide the industry with a clear and concise proposed definition to the System Operating Limit (SOL) term, a formalized definition to SOL Exceedance is not warranted. Furthermore, we believe that the proposed definition to SOL Exceedance is problematic and confusing with potential operational and compliance implications. We are concerned that the SDT definition and application of the term "stability limits" differs from the NERC approved glossary definition of "Stability Limits". This term, "Stability limit" is also used in the NERC SOL Whitepaper. CenterPoint energy urges the SDT to have further discussions and considerations towards the use of "stability limits" for proper alignment with the NERC defined term as well as how the term is used in the NERC SOL Whitepaper for clear representation to the industry.	
Likes 0	
Dislikes 0	
Response	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	No

Document Name	
Comment	

Hoosier Energy strongly disagrees with the proposed definition of SOL exceedance. Hoosir supports the following:

1. The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause **huge unintended consequences on large spectrum of the Industry's participants**.

2. The first major problem with the SDT's proposed definition of the SOL exceedance is **that it would expose a large number of TOPs and RCs to compliance risk unless enormous resources and efforts are added within each TOP's/RC's organization to keep up with (an order of magnitude) higher compliance administrative burden**.

3. The second major problem is that this definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, we believe the definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. We believe that a potential unintended outcome to avoid the administrative burden is operating **in an unnecessarily conservative operation.** We believe the SDT has ignored a fundamental fact that the implementation of Operating Plan, even in current industry's practice, is already being triggered by existing mechanisms, such as SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

4. The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate this infrastructure**. In other words the *SOL exceedance definition should be focused on defining what is considered to be **unacceptable operation** rather than what should be **good operating practice based recommendable operation***.

Therefore, we strongly **recommend that the SDT defers voting/ballots** on this item until such time that the following tasks are completed:

- **Perform comparative analysis of existing SOL definitions nation-wide**, in order to get an informed insight as to where majority of industry's participants stand on this definition.

- **Perform analysis of additional staffing resources and tools** that would be needed to implement proposed definition.

- **Outline and assess compliance driven administrative burden** that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.

- **Evaluate a risk of overwhelming and distracting real-time operations people** with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.

- **Assess the impact of significantly constraining business in the industry** associated with the industry's **inability to approve and perform numerous scheduled outages** (with many of them mandated by other NERC standards), as this conservative definition of SOL exceedance would simply make impossible many of these outages to proceed without causing SOL exceedances.

- Assess the impact that the proposed definition would have **on efficiency of market operations and associated cost**.

We re-iterate our ***recommendation that SDT re-considers adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint***, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:

1. It is *much more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*

2. *It would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.

3. It would provide *comparably reliable operation* of power systems.

4. It is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".

5. It would *prevent potentially huge increase of cost* of market operations.

6. It provides *more clarity and avoids ambiguity and interpretation issues*.

7. It is *much more acceptable to vast majority of Industry participants* as opposed to relatively small subset of industry participants that can afford use of advanced tools and other resources, including, but not limited to staffing and support personnel.

MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***
- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***
- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***
- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***
- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***
- ***Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

See the response to Q7.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1,3,5

Answer	No
Document Name	

Comment

Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to
"Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes that a TOP should be able to exceed a Normal Rating while utilizing an Emergency Rating (with a time-dependency) without logging an SOL Exceedance or notifying their RC of the actions taken (the action taken was to use an Emergency Rating). Using an Emergency Rating for the appropriate amount of time has no impact to system reliability and is using the "applicable" rating as identified in the NERC SOL Whitepaper.

Given the drafting team's SOL Exceedance proposal, a TOP would have to document their initiation of an Operating Plan and call their RC each time a Normal Rating is exceeded. BPA believes that this is an undue burden on the TOP and their RC and that the use of an Emergency Rating is normal operating procedure, not an SOL Exceedance.

BPA proposes this definition for SOL Exceedance:

An operating condition or analysis result characterized by any of the following, as determined in Real-time Assessments (RTA) or Operational Planning Analysis (OPA):

The pre-Contingency state indicates any of the following:

- *Actual flow through a Facility is above the Facility's highest Emergency Rating, or above an Emergency Rating for longer than the associated time*
- *Actual bus voltage is below the System Voltage Limit*

- *Actual bus voltage is above the highest System Voltage Limit, or the actual bus voltage is above a time-dependent System Voltage Limit for longer than the associated time*
- *A stability limit established to prevent instability without a Contingency is exceeded*
- *A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The calculated post -Contingency state indicates any of the following:

- *Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*
- *Bus voltage is outside the highest or lowest System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur*
- *Defined stability performance criteria are not met*

The proposed NERC defined term System Voltage Limit is used in the proposed definition of SOL Exceedance. System Voltage Limit is in a separate NERC posting out for comment, but since BPA will be proposing a revision to the definition of System Voltage Limit, BPA has used this revised definition in the comments submitted by BPA on the SOL Exceedance definition. Subsequently, BPA thinks it is relevant to share this revised definition with the drafting team now.

BPA proposes the following revisions to the definition of System Voltage Limit:

"The minimum steady -state voltage (pre-Contingency and post-Contingency) that provide for acceptable System performance. The maximum steady -state voltage ... base performance."

When addressing the post-Contingency bus voltage in the SOL Exceedance, the use of "emergency" is redundant given BPA's revised definition of System Voltage Limit because "Emergency Rating" is included in the revised definition.

Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	No
Document Name	
Comment	

Glencoe re-iterates our strong disagreement with the proposed definition of SOL exceedance. We express our disappointment with SDT's reluctance to incorporate our original comments and suggested changes that we submitted during the August 2016 commenting period.

The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause **huge unintended consequences on large spectrum of the Industry's participants**.

The first major problem with the SDT's proposed definition of the SOL exceedance is **that it would expose a large number of TOPs and RCs to compliance risk unless enormous resources and efforts are added within each TOP's/RC's organization to keep up with (an order of**

magnitude) higher compliance administrative burden.

The second major problem is that this definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, we believe the definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. We believe that a potential unintended outcome to avoid the administrative burden is operating **in an unnecessarily conservative operation.** We believe the SDT has ignored a fundamental fact that the implementation of Operating Plan, even in current industry's practice, is already being triggered by existing mechanisms, such as SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate this infrastructure**. In other words the *SOL exceedance definition should be focused on defining what is considered to be **unacceptable operation** rather than what should be **good operating practice based recommendable operation***.

Therefore, we strongly **recommend that the SDT defers voting/ballots** on this item until such time that the following tasks are completed:

Perform comparative analysis of existing SOL definitions nation-wide, in order to get an informed insight as to where majority of industry's participants stand on this definition.

Perform analysis of additional staffing resources and tools that would be needed to implement proposed definition.

Outline and assess compliance driven administrative burden that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.

Evaluate a risk of overwhelming and distracting real-time operations people with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.

Assess the impact of significantly constraining business in the industry associated with the industry's **inability to approve and perform numerous scheduled outages** (with many of them mandated by other NERC standards), as this conservative definition of SOL exceedance would simply make impossible many of these outages to proceed without causing SOL exceedances.

Assess the impact that the proposed definition would have **on efficiency of market operations and associated cost**.

We re-iterate our ***recommendation that SDT re-considers adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint***, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:

It is *much more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*

It would provide for significantly less administrative burden on numerous Industry's entities related to providing evidences of compliance.

It would provide *comparably reliable operation* of power systems.

It is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".

It would *prevent potentially huge increase of cost* of market operations.

·It provides *more clarity and avoids ambiguity and interpretation issues*.

It is *much more acceptable to vast majority of Industry participants* as opposed to relatively small subset of industry participants that can afford use of advanced tools and other resources, including, but not limited to staffing and support personnel.

MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

Actual steady state flow on a BES Facility is greater than the Facility’s highest Emergency Rating for any time period.

· ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.

The SDT determined that any **persistent** exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an **acceptable duration**. We disagree with SDT’s insistence on using Normal Rating **and re-iterate our recommendation to use Emergency Rating.** The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses ***no reliability repercussions as long as the flow on facility is returned below normal rating during time that was assigned for the emergency rating***. In the matter of fact, this is one of main reasons that transmission operators are given an emergency ratings and that fact should be correspondingly recognized in the SOL exceedance definition.

The SDT’s rationale to use Normal Rating in order to “trigger implementation of Operating Plan” is confusing. TOPs are perfectly aware of the limitations associated with the use of Emergency Rating and their obligation to return the flow below Normal Rating within specified time-frame**. Furthermore, hard-coded SCADA based operational alarms will trigger implementation of Operating Plan. Therefore, it is absolutely unnecessary to adopt conservative definition of SOL in order to “remind” TOPs and RCs of their well understood obligation to return flow under Normal Rating in specified time-frame**.

Secondly, although SDT stated that the their goal is to improve clarity and eliminate ambiguity they increase ambiguity and open another issue of interpretation by introducing the term **“persistent** exceedance of a Normal Rating”. The time of exceedance has to be clearly specified in this component. Otherwise, how will entities, including Auditors, measure “persistency” of exceedance?

The proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden and unnecessary increase of the cost of market operations while providing marginal benefit to system reliability as TOPs/RCs are under obligation to protect facilities on a contingency basis, which will consequently protect that facility against real-time flow exceedances.

We recommend the following definition:

· ***Actual steady state flow on a BES Facility is greater than the Facility’s highest Emergency Rating for any time period.***

· ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Component #4 – *The pre* Outside normal System Voltage Limits *Actual bus voltage is*

We disagree with SDT’s insistence on using Normal System Voltage Limits and recommend using Emergency Voltage Limits. Our arguments regarding the Component #4 are similar to our comments concerning the Component #3.

The technical rationale for our recommendation is based on the fact that **TOPs/RCs do operate their systems within normal voltage limits during vast majority of the time**. However, there are rare instances when sudden events and changes to operating conditions, or periods during switching long transmission lines, require use of emergency voltage limits. That is why *SOL exceedance definition should be focused on what is considered to be unacceptable operation rather than what should be recommended operation*. Again, the proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden.

We recommend the following definition:

Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

Component #5 – *The pre* *-Continge*

Component #6 – *The pre* *ncy state in Stability is exceeded*

The SDT apparently concluded that there is a reason to differentiate between stability limit occurring without contingency and stability limit that is contingency based and conditioned. We do not see reason that would be strong enough in order to justify existence of two components related to stability limits.

We believe that the physical nature of the stability limits is best addressed within individual Operating Plans. Therefore, there is no need to separate different natures of stability problems within definition of SOL exceedance. We believe that this is unnecessary complication and could be resolved by merging two subcomponents into the one.

We also find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%).

We recommend the following definition:

· ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***

Component #7 – *The calculated post* *-Contin* *or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*

The SDT provided clarification of their position by pointing out the (Project 2014 -03 White Paper) two highlighted items in the diagram. The portion highlighted in yellow, according to the SDT's explanation) " is considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan".

First, we need to draw attention of the SDT that the original version of the NERC White Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability impact so that it has localized impact**". Subsequent version of the NERC White Paper (revision of January 2015) introduced statement that "Post-contingency flow in this range is not acceptable" . **This revision, with a major impact, was never presented to the industry, never approved by the Industry and in our opinion was step in the wrong direction**.

The SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar.

It is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability.

The portion of the definition that states, *"…or above a Facility Rating for which there is not **sufficient time** to reduce the flow to established acceptable levels should the Contingency occur"* is intended to address the operating state highlighted in light blue. **This portion of the definition will be permanent source of major troubles for the industry, from the implementation prospective**. It **introduces ambiguity and confusion, because TOPs/RCs would be faced with hard and sometimes impossible task to determine what actually is "sufficient time" for any specific set of operational circumstances**. This time might be dependent on ramp rates of the units but also on efficiency and speed of congestion management procedures (such as LMP binding). **This may also cause huge cost to market operations, while providing marginal benefits to system's reliability**.

We recommend the following definition:

Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.

Rationale for using Post-contingency action plan concept

The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating****.* It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

In contrast to this, we think that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this fashion and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that it might be argued that the TOP has to establish a new Short Emergency rating in contrast to agreeing with its RC on post-contingency action plan. Issuing a new Short Term Emergency rating should be considered as a legitimate alternative, indeed. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings**) for every single piece of equipment (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data**. Consequently, each TOP and RC would need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6

Answer	No
Document Name	

Comment

It is felt that an SOL Exceedance has not occurred until both a limit and corresponding time frame have been surpassed, which is supported by the SOL whitepaper. If a Facility has a Normal Rating and corresponding 4-hour Emergency Rating, reliable operation can occur even after surpassing the Normal Rating (but still less than the Emergency Rating) for less than 4 hours. Operating in an allowed reliable state should not be an SOL Exceedance. SOL Exceedances should be to the true binding limitations of the system for purposes of consistency. This does not preclude an operator from taking action, but should not be required if reliable system operation has been determined within this range. This should be true for both pre- and post-contingent discussions as long as mitigation can take place within the allotted timeframe.

As currently written, pre-contingent and post-contingent definitions are inconsistent. A post-contingent Normal Rating exceedance that can be mitigated with its allowable timeframe would immediately become an SOL exceedance if the contingency occurs.

Suggested language as follows:

*A **binding and valid** operating condition or analysis result characterized by any of the following, as determined in Real etime Assessments (RTA) or Operational Planning Analysis (OPA):*

The pre -Contingency state indicates any of the following:

- *Actual flow through a Facility is above the Facility's **respective rating (Normal or Emergency) longer than the allowable time defined by the TOP***
- *Actual bus voltage is outside **acceptable** System Voltage Limits **longer than the allowable time defined by the TOP***
- *A stability limit established to prevent instability without a Contingency is exceeded*
- *A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The calculated post -Contingency state indicates any of the following:

- *Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which **it is known that flow would exceed the rating longer than the respective allowable time defined by the TOP should the contingency occur***
- *Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which **it is known that the voltage would remain outside the limit longer than the respective timeframe defined by the TOP** should the Contingency occur*
- *Defined, non-limit based stability performance criteria are not met as determined by those entities with the capabilities and processes to do so*

*Valid and binding shall ensure that conditions or results flagged are of sufficient accuracy and consistency. Nuisance (i.e., intermittent alarming) conditions or results shall not be considered a binding SOL Exceedance.

Likes 0	
Dislikes 0	

Response

Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities

Answer	No
Document Name	

Comment

Colorado Springs Utilities finds the Project 2014-03 SDT's rationale for what constitutes an SOL Exceedence to be compelling and reasonable. The proposed definition in question strays from the White Paper produced by that Project (and subsequently adopted as "ERO Enterprise-Endorsed Implementation Guidance") in a significant way - that of being able to fully utilize all applicable thermal ratings and associated time frames in Real-time.

The purpose of SOLs is to "ensure operation within acceptable reliability criteria," and entities establish thermal SOLs, including any so-called "emergency" ratings and their attendant time limits, with those criteria in mind.

From the White Paper, "SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance." In other, other words; operating, Real-time, with MW flows above a Facility's normal/continuous thermal rating but below a time-limited "emergency" rating for a time not exceeding the applicable time-limit is acceptable system performance and, thus, not an SOL Exceedance. This is straight-forward logic, and conforms with the White Paper you reference.

TOP-001-3, R14, requires, "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." Colorado Springs Utilities believes this requirement is met, in spirit and in letter, by an entity implementing an Operating Plan to prevent exceeding the time limit imposed by any specific, applicable thermal SOL. This requirement would also be met, in spirit and in letter, by an entity recognizing that operating slightly above the normal/continuous rating (but below the time-limited "emergency" rating) will only persist for a time less than the applicable time limit due to the forecasted load curve and taking no specific action other than monitor.

Therefore, Colorado Springs Utilites requests changing the first bullet under the "pre-Contingency" list to read:

• Actual flow through a Facility is above the applicable Facility Rating for an unacceptable time duration

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

While AEP agrees overall with the proposed definition, we are unsure of the need to include the text “Real-Time monitoring.” Unlike Real-time Assessments and Operational Planning Analysis, the phrase “Real-Time monitoring” is not a NERC glossary term. If “Real Time Assessment” is not already encompassing enough, what additional operating conditions or analysis would be brought into scope by including “Real-Time monitoring” in the definition?

AEP seeks clarity on the use of the term “calculated” relative to the post-contingency state. Nowhere in the technical justification, or as phrased in the question above, does it clarify the need to distinguish between calculated or actual post-contingency states.

Likes 0	

Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
The addition of the definition of SOL Exceedance is necessary in conjunction with the modification of the definition of SOL.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Idaho Power agrees with the proposed definition, but recommends a wording change to the post-contingency facility rating bullet. Instead of "the Facility's highest Emergency Rating," the definition should state that flows should not exceed "the Facility's highest Emergency Rating for the operating conditions." For example, winter ratings should not be used for summer operating conditions.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
We think the "or analysis result" is not necessary considering the reference to RTA and OPA. We appreciate the introduction of time to reduce the flow in the assessment of an operating condition. We suggest to reword "A stability limit established to prevent a (instead of the) Contingency from resulting in instability is exceeded". Also, same comment as for the SOL definition regarding the use of the non-defined term stability limit and the link with the interface concept.	

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak agrees with the SDT's proposed defintiion of SOL Exceedance and with the arguments set forth in question #4 and with those set forth in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale."

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

The proposed definition makes clear the concept of SOL Exceedance as separate from an SOL.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Comments: Texas RE generally agrees with the SDT's approach to separate the definition of System Operating Limits (SOLs) from the definition of an "SOL Exceedance." In particular, Texas RE agrees with the NERC-endorsed implementation guidance that "[i]t is important to distinguish operating practices and strategies from the SOL itself." That is to say, while SOLs are based on an entity's actual set of Facility Ratings, voltage limits, and Stability Limits monitored in pre- and post-contingency states, SOL Exceedances should reflect performance within all applicable limits over the time horizon at issue. The SDT appears to take appropriate steps to clarify that distinction. With these general comments in mind, Texas RE notes one area that could further enhance the new SOL and SOL Exceedance definitions. In particular, both the SOL and SOL Exceedance definitions refer to "stability limits" and do use the existing NERC "Stability Limit" definition. "Stability Limit" is currently defined as: "[t]he maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers." The SDT should consider using the existing Stability Limit definition or, alternatively, revise the definition to reflect the new SOL and SOL Exceedance definitions. At a minimum, Texas RE requests that the SDT identify the aspects of the existing Stability Limit definition that warrant using the non-defined term.	
Likes 0	
Dislikes 0	
Response	

5. Considering the explanations provided here and further explained in the definitions rationales, do you agree that the proposed SOL Exceedance definition should include this bullet item? Please explain your response and/or provide alternative language.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Question #5 states that "If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance." While we agree with this view, we do not believe it is obvious or apparent when looking solely at the proposed definition only. We believe any such clarity or insight should be added to the definition itself.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
While the intention is good, stability performance criteria are more subjective than thermal and voltage criteria. The acceptability of stability performance may vary more than that of thermal and voltage acceptability. This definition may unnecessarily invite the determination of non-compliance.	
Likes 0	
Dislikes 0	
Response	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
Colorado Springs Utilities is not so optimistic to believe that, "If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC …" We believe it is the natural tendancy of a regulatory body to enforce	

regulations rather indiscriminately once codified, regardless of the intent of the authors. Colorado Springs Utilities is also bemused by the presumption that entities won't take appropriate responses without a regulatory "trigger."

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6

Answer	No
Document Name	

Comment

Without stating in some way the rationale in the definition itself, it could easily be interpreted that some form of action would be required of all entities, not just those that have the capability to perform these types of studies. It is clear that the intent is not requiring real-time stability analysis tools; therefore, a clear distinction must be made to ensure this only applies to certain entities.

Suggested language:

Defined, ***non-limit based*** *stability performance criteria are not met* ***as determined by those entities with the capabilities and processes to do so***

Likes 0	
Dislikes 0	

Response

Terry Volkmann - Glencoe Light and Power Commission - 1

Answer	No
Document Name	

Comment

We consider this portion of the definition as unnecessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations (which we recommend to also be merged within one clearly defined stability related bullet. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA suggests that the definition spell out: “If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance.” An entity should not have to search for when it is applicable. BPA would like the context added to the definition.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q7.	
Likes 0	
Dislikes 0	
Response	

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
This portion of the definition as unnecessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations (which we recommend to also be merged within one clearly defined stability related bullet. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	

Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
Including this bullet seems to put additional burden on TOP's and RC's utilizing real time tools to determine if stability criteria are being met. This may inadvertently discourage entities from implementing these types of real time tools that could help to enhance reliability. In addition, the rationale document states that "If the TOP or RC does not utilize Real-time stability tools to determ ngency events and to evaluate that response against defined stability performance criteria, but solely utilizes a more traditional approach for establishing stability limits (i.e., limit "values") to address system instability, then the third bullet in the post-Contingency section of the p Contingency definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section o Stability performance." However the definition itself does not list any exclusions or state that this bullet is "above and beyond". The definition used in a standard should clearly state the applicability and should exclude this bullet if the SDT considers it only applicable to entities with certain tools.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Entergy believes that this bullet item is not necessary since the stability is covered in the pre-contingency part.	
Likes 0	

Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The proposed definition assumes each applicable entity possesses its own on-line stability tools or are actively monitoring its operating parameters to indicate the next Contingency that could result in instability. This may not always be the case. Moreover, what happens if an entity loses the availability of these tools? We believe the addition of this bullet to the definition is unnecessary, as applicable entities will likely take appropriate action to avoid the possible exceedance of a stability limit in the pre -Contingency state.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Our proposed definition covers both established stability limits and stability limits determined using Real-time tools making this distinction unnecessary.	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The proposed definition assumes each applicable entity possesses its own on-line stability tools or are actively monitoring its operating parameters to indicate the next Contingency that could result in instability. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations. Per our recommendation to utilize the MISO definition in question #4, we believe these two bullets could be combined into one clearly defined stability related condition. Those entities that use real-time stability tools should use the third and fourth bullets under pre-	

Contingency operations as well or the single definition, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
This portion of the definition isn't necessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
NIPSCO feels the use of "sufficient time" in the definition is vague. Who defines "sufficient time"? Is it the RC or the TO? Again NIPSCO likes the MISO definition as it is more descriptive. It reads as follows: SOL Exceedance Based on Projected Post-Contingent Flows, Determined by a Real-Time Assessment A. Projected post-Contingent loading on a BES Facility is greater than the highest emergency rating for longer than 30 minutes with **NO** agreed upon action plan that would mitigate the condition if the Contingency were to occur. B. Projected post-Contingent voltage on a BES Facility is less than the emergency low voltage limit for longer than 30 minutes with **NO** agreed upon action plan that would mitigate the condition if the Contingency were to occur.	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees that the definition of SOL Exceedance should include the item "Defined stability performance criteria are not met." However, it should be made clear to auditors that this aspect of the defintion applies only to entities that use real-time tools to determine whether the system is meeting stability performance criteria or not. I.e., if a TOP or RC is not using real-time tools, but is instead using actual predetermined stability limits (limit "values") in accordance with the last two bullets in the pre-Contingency section of the proposed definition of SOL Exceedance, then the bullet in question should not apply to that TOP or RC.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
IRC agrees with including this item; however, IRC suggests clarifying that "defined stability performance criteria" refers to criteria defined by the RC in its SOL Methodology, as follows: · Stability performance criteria *defined by the RC in its SOL Methodology* are not met	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation recommends, if it is the intent of the third post-Contingency bullet to only apply to those TOPs or RCs that additionally use real-time tools to determine whether defined stability performance criteria are being met, that the bullet explicitly state this applicability criterion so as to provide clarity and avoid confusion.	
Likes 0	
Dislikes 0	

Response
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	Yes
Document Name	

Comment
The definition allows TOPs and RCs to recognize that the standards are about maintaining an adequate level of system performance for all customers. Many reliability issues are not adequately captured by traditional SOL values and are best measured by other system parameters. Although ATC agrees that the inclusion of this bullet is acceptable, the term "stability" with this bullet may cause confusion for some entities. Another possible term to use is "Defined system performance criteria are met".

Likes 0	
Dislikes 0	

Response
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

6. The SAR is being revised to authorize the SDT to review the existing body of Reliability Standards and NERC Glossary of terms, and where necessary, modify those standards and definitions to incorporate the new terms and/or definition(s) of SOL Exceedance and System Voltage Limit, as well as the revised definition of System Operating Limit. The SDT has identified the standards and terms they contend would benefit from this incorporation and has included them in separate documents with this posting for your review. Do you agree with the SDT's selections? If not, please explain your response.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	

Comment

Refer to the comments for Question 3 that identify the need for Stability Limits definition.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The current definition of SOL has been the foundation of the existing suite of Reliability Standards, in addition to operating practices, since 2007. Any change in the definition of SOL and the implementation of the new definitions needs to be carefully coordinated with updates to existing standards to accommodate the revised definition.

IRC has identified the following additional four Reliability Standards that it believes should be considered for updates included in the SDT Spreadsheet:

MOD-001-2 R1.1 The requirement should be changed to acknowledge the new definition

PER-004-2 R2 The VSLs needs to be modified since they were written with the 'most limiting' of ratings to be considered. The proposed definition includes the entire universe of ratings which I don't believe was the intent of the VSLs.

VAR-001-4.1 R1 The requirement should be changed to acknowledge the new definition.

Interconnection Reliability Operating Limit Glossary of Terms Need to replace violated with exceeded.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT ISO signs on to the SRC comments.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Since we don’t agree that a definition for SOL Exceedance is needed, there is no need to incorporate it into these other standards.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe the SDT should expand their review to any reference to the phrase "limit," in the context of System Operating Limits, in the NERC Reliability Standard and NERC Glossary. This includes the addition of glossary terms like Emergency Rating, Flowgate Methodology, Rating, and Reliable Operation. 2. The scope of the SAR should also be expanded to consider the review of applicable requirements that could be retired under various Paragraph 81 criteria.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q7.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TPL-001-4 is absent from the list. While TPL-001-4 does not explicitly mention SOLs, Table I does discuss stability limits and facility and voltage ratings.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican agrees with the SDT’s selection.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
The SDT should take the opportunity of this revision to ensure that clarity exists when other standards refer to deliverables or language used in the current FAC standards. For example, CIP -002-5.1a criterion 2.6 refers to a list of facilities critical to the derivation of IROL used in FAC-014, but the current FAC-014 does not explain in any way what critical facilities are versus non-critical facilities.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the SDT's selections.	
Likes 0	
Dislikes 0	
Response	

Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe agrees with the SDT’s selection	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Care should be taken on implementing this definition. Once formal (capitalized) definitions become effective, entities will use that explicitly when complying with NERC standards. For example, confusion can occur if standards incorrectly use “SOL exceedance” or “exceeding an SOL” vs “SOL Exceedance. There must be a way to ensure continuity so that the intent of the requirement is clear.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA appreciates your consideration of the time and effort we put into our comments and sincerely hopes that we can influence change.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	
Document Name	v4 LSPT Q7 attachment SOL, SOL Exceedance comments.docx
Comment	
Due to SBS formatting limitations, the Q7 response is separately attached.	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
1. We believe the SDT should have included a request for comments on its proposed definition for System Voltage Limit, since this definition directly ties to the SOL definition. The references to normal and emergency in this definition do not aligned with the proposed SOL and SOL Exceedance definitions. Further guidance on what constitutes "acceptable performance" is also needed. 2. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	

Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Great River Energy believes the SDT should have included a request for comments on its proposed definition for System Voltage Limit, since this definition directly ties to the SOL definition.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	
Document Name	
Comment	
The definitions addressed here achieve the objective of "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." It should be noted that the consistency in the definition of SOLs and application of SOLs to determine SOL Exceedances does not translate as a consistent, comparative indicator of reliable system performance. The contingencies applied to establish an SOL Exceedance event are bounded only by a floor of three contingencies mandated by FAC-011. OPAs and RTAs determine SOL Exceedances in accordance with the local SOL methodologies. SOL methodologies may or may not significantly expand the applicable contingencies which define SOL Exceedances. Comparing SOL Exceedances from one SOL methodology to the SOL exceedances of another SOL methodology can be a case comparing apples to oranges.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT ISO signs on to the SRC comments.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The definitions addressed here achieve the objective of "bringing clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."

It should be noted that the consistency in the definition of SOLs and application of SOLs to determine SOL Exceedances does not translate as a consistent, comparative indicator of reliable system performance. The contingencies applied to establish an SOL Exceedance event are bounded only by a floor of three contingencies mandated by FAC-011. OPAs and RTAs determine SOL Exceedances in accordance with the local SOL methodologies. SOL methodologies may or may not significantly expand the applicable contingencies which define SOL Exceedances. Comparing SOL Exceedances from one SOL methodology to the SOL exceedances of another SOL methodology can be a case comparing apples to oranges. However, this project will result in the application of SOLs in the OPA and RTA being consistent regardless of disparity in the methodologies between different RCs.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	

Comment

It is premature for industry to vote on FAC standards using the current definition as requested. While it would be nice to decouple the new standard and the revised SOL definitition, the revised definition fundamentally impacts how the FAC standards will be implemented. Therefore, entities must vote on the NERC standard based on the expected revised SOL definition. Where the combination of the revised definition and standard would cause concerns, then industry should vote negative accordingly. The two things cannot be effectvely decoupled.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

1. The proposed definition of SOL Exceedance, if employed, will cause confusion as to what is a violation. For example, if flow on a line goes beyond its post-contingency STE (the highest time-based rating), should it not be considered a violation as opposed to an exceedance despite the fact the contingency has not occurred? This new definition should also identify which exceedances should also be treated as violations in the interest of eliminating confusion as to what is a SOL violation vs. what is an exceedance. Alternatively, having a definition for SOL Violation may provide the required clarity.

2. The proposed definition of System Voltage Limit seems unnecessary and the associated background information causes confusion around voltage Facility Ratings vs. System Voltage limits. System voltage limits are either present to either protect system equipment from damage or to prevent instability of the system. Therefore this defined term is not needed. The background from Q3 of this comments form states, "Facility Ratings and System Voltage Limits are not determined by a "study"; rather they are inputs to the "study". This confuses the term further as a System Voltage Limit definition further as voltage limits which are not Facility Ratings must be studied whenever system configurations are different from what has been previously studied.

3. The proposed definition for SOL must include the glossary term "Stability" definition. Use of lower-case stability with an accompanying explanation is not sufficient to allow industry to be of a common understanding. A common understanding of "Stability" is fundamental in ensuring Interconnected System Reliability. The definition of Stability must be inclusive of what could be deemed instability; this includes thermal violations would cause cascading outages.

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	
Document Name	

Comment
Not Applicable

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2015-09 Establish and Communicate System Operating Limits | SOL and SOL Exceedance Definitions
Comment Period Start Date:	9/29/2017
Comment Period End Date:	10/30/2017
Associated Ballots:	

There were 36 sets of responses, including comments from approximately 92 different people from approximately 74 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to revise the current SOL definition? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need to modify the SOL definition at all.) Please explain your response.

2. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to create and implement a definition for SOL Exceedance? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need for having a definition of SOL Exceedance.) Please explain your response.

3. Considering the simplified approach to SOLs described here and the explanations provided in the definitions rationales, do you agree with the proposed SOL definition? Please explain your response and/or provide alternative language.

4. Considering the explanations provided in the definitions rationales, do you agree with the proposed SOL Exceedance definition? Please explain your response and/or provide alternative language.

5. Considering the explanations provided here and further explained in the definitions rationales, do you agree that the proposed SOL Exceedance definition should include this bullet item? Please explain your response and/or provide alternative language.

6. The SAR is being revised to authorize the SDT to review the existing body of Reliability Standards and NERC Glossary of terms, and where necessary, modify those standards and definitions to incorporate the new terms and/or definition(s) of SOL Exceedance and System Voltage Limit, as well as the revised definition of System Operating Limit. The SDT has identified the standards and terms they contend would benefit from this incorporation and has included them in separate documents with this posting for your review. Do you agree with the SDT's selections? If not, please explain your response.

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Colorado Springs Utilities	Brandon Ware	1,3,5,6		Colorado Springs Utilities	Brandon Ware	CSU	1	WECC
					Shannon Fair	Colorado Springs Utilities	6	WECC
					Jeff Icke	Colorado Springs Utilities	5	WECC
					Hillary Dobson	Colorado Springs Utilities	3	WECC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power	1,5	Texas RE

						Cooperative, Inc.		
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Lucia Beal	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC
					Mark Holman	PJM	2	NPCC
					Charles Yeung	SPP	2	SPP RE
					Nathan Bigbee	ERCOT	2	Texas RE

					Ali Miremadi	CAISO	2	WECC
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE and NGrid	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC

Randy MacDonald	New Brunswick Power	2	NPCC
Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC

					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Ed	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated	3	NPCC

						Edison Co. of New York		
					Brian O'Boyle	Con Ed	5	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Kidwell	Empire District	1,3,5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Nathan McNeil	Midwest Energy, Inc	NA - Not Applicable	SPP RE

1. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to revise the current SOL definition? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need to modify the SOL definition at all.) Please explain your response.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed definition revision provides additional information on the determination of SOLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	
Colorado Springs Utilities supports the SDT's proposal to revise the current SOL definition.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that greater clarification will be good for the industry. BPA is in support of modifying the SOL definition as long as the SOL Exceedance Definition is also created.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") supports the SDT's proposal to revise the current definition of SOL and generally supports the revised definition with the exception of the use of "stability limit" within the definition of SOL. We understand from comments made during an industry webinar that this use of "stability limits" is not the same definition of "Stability Limits" used in the NERC Glossary. We believe this to be confusing to the industry. If the SDT's use of the term does not align with the NERC glossary term, then it needs to be clearly represented for the industry to know and understand the difference. Additionally, the NERC SOL whitepaper also uses a variation of "Stability limit".	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. As is stated in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale", *"the intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance."* The revision of the Stability Limit defined term is outside the scope of the SDT at this time. However, if the definition of Stability Limit is modified at some point in the future, the industry should consider modifying the SOL definition to include this term.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
ITC agrees that the current System Operating Limit (SOL) definition is ambiguous. Clarifying the definition of a SOL will help to provide consistency and improve reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Duke Energy agrees that revising the definition of an SOL would be beneficial for the industry. Some confusion still exists as to what actually constitutes an SOL.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports the need for revising the definition of SOL and creating a new definition for SOL Exceedance. Peak believes that the SOL definition needs to be revised and that a clear definition for SOL Exceedance needs to be created and implemented in the body of the NERC Reliability Standards. Doing so would result in improved clarity and consistency and would prevent entities from adopting interpretation of SOL Exceedance that do not provide the level of reliability intended by its use in the TOP and IRO standards. Peak also believes that the key events mentioned in question #1 do not provide a sufficient basis for addressing the clarity and consistency problems associated with the current definition of SOL and the absence of a definition for SOL Exceedance as described in the supporting document "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes

Document Name	
Comment	
Great River Energy supports the SDT’s revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
The revision is necessary to better capture industry practice and alignment with TOP/IRO standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy Company (MEC) supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	

Modifying the SOL definition is appropriate in conjunction with the addition of the definition of SOL Exceedance. Together, these definitions provide clarity and eliminate possibilities for confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	

2. Given the above, and considering the rationale provided in the supporting document, do you support the SDT's proposal to create and implement a definition for SOL Exceedance? (Clarification: this question is not asking of you agree with the proposed definition. That will be addressed in a separate question. This question is focused on the need for having a definition of SOL Exceedance.) Please explain your response.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	

Comment

The justification for creating an SOL Exceedance definition, as described in the "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale" document, is speculative in nature. Specifically, the SDT expresses the concern that "[o]ne TOP might interpret SOL exceedances to not include the post-Contingency state when identifying SOL exceedance". However, the existing NERC definitions for OPA and RTA coupled with the requirements of the TOP-001-3 and TOP-002-4 standards logically combine to require an entity to evaluate the system for SOL exceedances for the post-Contingency condition. As such, there is insufficient reasoning to create a new definition for SOL Exceedance.

The SDT's concern appears to be with the wording of TOP-001-3 R14. Although ATC believes that there is no conflict or gap, a SAR could be written to improve the TOP-001-3 R14 requirement if the SDT still believes that there is an issue with the language.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
We do not believe it is necessary that NERC define SOL Exceedance. Operating outside an SOL in Real-time is an exceedance of the limits. An SOL that is predicted to be exceeded using RTA and OPS is a predicted exceedance, or a potential exceedance, but until it actually happens, it is not an exceedance. We believe it is important to keep a Real-time exceedance and an exceedance predicted by RTA or OPA separate from each other.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy does not support the creation and implementation of a definition for SOL Exceedance. We believe that the proposed term SOL Exceedance could potentially confuse the industry and take away from the clarity provided to the industry with the proposed revisions of the SOL definition. Furthermore, we believe that the proposed revisions to the definition of System Operating Limit (SOL) provide the industry with a clear and concise definition of the term; therefore, the industry understands that an exceedance to an SOL is when the applicable electrical values have gone beyond those established Facility Ratings limits, System Voltage Limits, and stability limits used in the operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
The addition of the definition of SOL Exceedance is necessary in conjunction with the modification of the definition of SOL.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
See our comments under Question 7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	

MidAmerican Energy Company (MEC) supports the SDT's proposal to create a definition of SOL exceedance, as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create	

an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Great River Energy supports the SDT's proposal to create a definition of SOL exceedance. However, the definition should not result in unintended consequences of imposing additional and undesirable administrative compliance burden to the detriment of system reliability. Additional administrative burden in an operational setting detracts from the reliable operation of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Peak supports the need for revising the definition of SOL and creating a new definition for SOL Exceedance. Peak believes that the SOL definition needs to be revised and that a clear definition for SOL Exceedance needs to be created and implemented in the body of the NERC Reliability Standards. Doing so would result in improved clarity and consistency and would prevent entities from adopting interpretations of SOL Exceedance that do not provide the level of reliability intended by its use in the TOP and IRO standards. Peak also believes that the key events mentioned in question #2 do not provide a sufficient basis for addressing the clarity and consistency problems associated with the current definition of SOL and the absence of a definition for SOL Exceedance as described in the supporting document "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that a definition of SOL Exceedance would be advantageous to the industry.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
ITC believes that defining SOL Exceedance will help to provide consistency and improve reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	

Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes the revision to the definition of SOL cannot occur unless SOL Exceedance is added to the Glossary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe supports the SDT's proposal to create a definition of SOL exceedance, as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

Colorado Springs Utilities agrees that a definition for SOL Exceedance would provide needed clarity in the various affected Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
There has been ongoing confusion of whether SOLs are limits or are violations. The proposed definition provides clarity for the distinction.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

3. Considering the simplified approach to SOLs described here and the explanations provided in the definitions rationales, do you agree with the proposed SOL definition? Please explain your response and/or provide alternative language.	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	
While very close, it is felt that a tweak to the language can provide clarity in how RTM, RTAs, and OPAs are performed. Consider using: "Facility Ratings, System Voltage Limits, and stability limits more restrictive than Facility Ratings (including margins if required) used in the operation of the BES." This ensures that RTAs and OPAs are not checked against Facility Ratings and then separately stability limits; it should only be the more limiting of the two. Other "studies" are still required to verify if stability limits are more restrictive, but are not needed as part of the RTAs and OPAs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is concerned that the proposed change may not add clarity to the proposed definition.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	

ITC agrees that the proposed SOL definition provides clarity and removes ambiguity. However, because the term "System Voltage Limit" is included in the definition of SOL, the definition of "System Voltage Limit" should be considered in this comment form. Assuming the definition of "System Voltage Limit" stands as currently proposed, ITC would approve of the proposed SOL definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Because the definition of System Voltage Limit passed the initial ballot, its inclusion in the definition of SOL in a future possible ballot should be acceptable.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
See our comments under Question 7.	
Likes 0	
Dislikes 0	
Response	
Response provided under Question 7.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	

Comments: ATC has three comments with the proposed SOL definition:

1. The existing SOL definition contains important language regarding the "applicab[ility]" of the limit used. This clarity is missing from the proposed SOL definition revision. ATC believes the existing definition is better than the proposed definition from this perspective although entities could read “applicable” into the proposed definition as needed.
2. The term SOL is not used in proposed standard FAC-015-1 for the planning horizon. However, the concept does exist in the proposed standard. The proposed SOL definition only calls out the operating horizon and would be improved by recognizing the planning horizon as well. ATC recommends that the proposed SOL definition be edited to address this omission with wording like, “. . . used in the operation and planning of the BES”.
3. Similar to ATC’s response to Question #5 (below), stability limits can be a difficult to understand term to use in the SOL definition, especially since it is undefined. The SOL Exceedance definition tries to aid entities that establish and monitor SOLs by including the terms “stability performance criteria” to cover a wider range of system phenomenon than traditional stability limits (e.g., voltage stability, angular stability, system stability). For question #5, ATC recommends the use of “system performance criteria” to recognize that the underlying issue may not be a traditional stability problem but some other important system performance limit that is being exceeded. The underlying system issue is then represented by a proxy “stability limit” to keep the system within the bounds of acceptable performance. It would seem that this type of clarification would be more reasonably provided in the SOL definition and not the SOL Exceedance definition. Alternatively, the SDT could create a “Stability Limit” definition, which would then be referenced in the SOL definition by using the capitalized term. If a Stability Limit definition is created, the definition would then need to clearly indicate that both traditional stability issues and other system performance criteria issues (such as voltage ride through curves, angle difference from system reference angle, margin from voltage collapse point, system damping attenuation, etc.) can be represented with Stability Limits.

Likes 0	
Dislikes 0	

Response

1. The SDT modified the proposed SOL definition to include the phrase “*applicable to specified System configurations*.”
2. The SDT does not believe that the SOL term needs to be included in FAC-015-1, nor does the SDT believe that the SOL term needs to be applicable to the planning horizon. The current planning standard TPL-001-4 and the proposed FAC-015-1 accomplish the intended planning reliability objectives without the use of the SOL term.

3. The SDT agrees with ATC on many points written here. The SDT modified the proposed SOL definition to include the phrase "*applicable to specified System configurations*." Additionally, requirement R4 in proposed FAC-011-4 includes a subpart requirements for the RC's SOL Methodology to specify stability performance criteria and to require that stability limits be established to meet those stability performance criteria. It is quite possible that resulting stability limits would be "proxy limits" that, if operated within, prevents the system from violating those performance criteria in the event of a Contingency. The revision of the Stability Limit defined term is outside the scope of the SDT at this time. However, if the definition of Stability Limit is modified at some point in the future, the industry should consider modifying the SOL definition to include this term.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

The proposed definition provides needed clarity.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities

Answer	Yes
Document Name	

Comment

Colorado Springs Utilities finds the revised definition of SOL acceptable and workable.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoen agrees with the definition of SOL proposed by SDT.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA's interpretation of a stability limit is often associated with a path.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the SDT's proposed revision of the SOL definition and with the arguments set forth in question #3 and with those set forth in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes

Document Name	
Comment	
We agree with the proposed definition, but in practice in order to remain within SOLs in operations is often the use of pre-determined transfer and monitoring of specific interfaces (either thermal, voltage stability, or transient stability). The concept is introduced in the rationale for component #5 and #6 of SOL exceedance, but more rationale regarding how a transfer interface is managed versus the simplified SOL definition would be helpful. Also, the use of "lower case" stability limits rather than the defined term causes some confusion. Why use the defined term for FR and SVL, but not stability limits? What is a stability limit for the purpose of the SOL definition?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with the comment. Page 3 of the NERC SOL White Paper states, *"It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity."* This concept was considered when formulating the proposed definition of SOL. Accordingly, if managing flow on an interface is an effective means by which to prevent or mitigate an SOL exceedance, then such actions can be implemented as part of an Operating Plan. Effectively, the Operating Plan is the mechanism for addressing SOL exceedances, and it can include trigger points for operator action based on Real-time Assessments or based on prior analyses. The definition of Operating Plan affords TOPs with the flexibility to address SOL exceedances in the most effective or efficient means necessary as determined by the TOP. As is stated in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale", *"the intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability*	

performance." The revision of the Stability Limit defined term is outside the scope of the SDT at this time. However, if the definition of Stability Limit is modified at some point in the future, the industry should consider modifying the SOL definition to include this term.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy Company (MEC) agrees with the definition of SOL proposed by SDT.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	

Answer	Yes
Document Name	
Comment	
Reclamation supports categorizing all Facility Ratings, System Voltage Limits, and stability limits as SOLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Theresa Allard - Minnkota Power Cooperative Inc. – 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michael Brytowski - Great River Energy - 1,3,5,6 – MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Laura Nelson - IDACORP - Idaho Power Company – 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

4. Considering the explanations provided in the definitions rationales, do you agree with the proposed SOL Exceedance definition? Please explain your response and/or provide alternative language.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	

The proposed SOL Exceedance definition is unworkable as written.

The definition has a fundamental flaw as it is attempting to create a one size fits all definition for two very different situations. The two situations are: (1) real-time situations (Real-time Monitoring and Real-time Assessments), and (2) static situations (Operational Planning Analysis). As categories of these situations imply, there are different time components associated with an SOL Exceedance in each situation that are not adequately addressed by the proposed SOL Exceedance definition.

There are three primary concerns with the definition as written and applied towards real-time situations: (1) the pre-Contingency language, (2) the post-Contingency language, and (3) purpose of the definition.

1. The pre-Contingency portion of the definition is not workable because it assumes a static system and does not account for timeframes associated with operating to various SOLs in real-time situations. Specifically, the first two bullets require the use of a "Facility's Normal Rating" and "normal System Voltage Limits", which are not applicable to a system that has just suffered a contingency. As recognized in the post-Contingency language, once a contingency has occurred the actual flow on the system may exceed the Normal Rating and/or the actual voltage may be outside of normal System Voltage Limits. Prior to the contingency occurring, this was not an SOL Exceedance but now that the contingency has occurred it shall be deemed an SOL Exceedance solely because of the definition's pre-Contingency language. The definition does not recognize that the new pre-Contingency state has flows below the "Facility's highest Emergency Rating" but above the Normal Rating. This condition is not an SOL Exceedance because the system is operating as designed and is not experiencing unacceptable system performance. Flows will be able to be returned below the Normal Rating within the applicable timeframe. The TOP should not have to deem this an SOL Exceedance because the SOL has not been exceeded.

2. The post-Contingency portion of the definition is not workable because is assumes a static system whereas there are constantly changing real-time inputs of a possible post-Contingency state. Assessing the post-Contingency state represents only a snapshot in time. However, due to the way contingency analysis tools work, it can be several minutes before another snapshot of the real-time inputs calculates the newly expected post-Contingency state. The definition means an entity has an SOL Exceedance for even a single post-Contingency state result, which may not be valid due to the fluidity of the system, especially in a market. Given the way the STD is intending to use the definition (i.e. as a driver of action to mitigate the issue), the post-Contingency language would need to include reference to a **persistent** post-Contingency state indication.
3. The SDT explains that the purpose of this definition is to drive an action, which is not the purpose of a definition. As stated in the rationale document (p. 9), the SDT believes the proposed definition "accomplishes the intended reliability objective of triggering an appropriate action". NERC definitions should not drive requirements for entities. Rather, this function is accomplished by the requirements within the NERC Standards. A proposed definition should define what an SOL Exceedance is or is not. The proposed definition does not create this level of clarity because the SDT has developed a definition with a particular required action in mind (e.g., see above regarding the "pre-Contingent state" language). A proposal for edits to the definition is given below and these proposed edits will achieve the intended outcome the SDT desires because the edits recognize the time-based nature of limits, which the SDT recognizes in its rationale document (cf. p. 11).

ATC recommends that the SOL Exceedance definition not be created. However, if the definition will be created, ATC recommends that the two separate definitions be created to recognize the difference between real-time and next contingency situations regarding SOL exceedances. If two definitions will not be created, at a minimum, edits must be made to the "pre-Contingency state" language so that the definition does not reference "normal" ratings or voltage limits. This specific language should be changed to refer to "applicable" ratings and "applicable" voltage limits because of the explanation above regarding the definition applying to real-time situations immediately following a contingency (i.e. what was not an SOL exceedance suddenly becomes an SOL exceedance, which is not logical from a definition standpoint).

Proposed definitions for SOL Exceedance in both RTA and OPA would bring clarity to the industry. The proposed definitions are as follows:

SOL Exceedance - Real-time:

An Operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring or Real-time Assessments (RTA):

The pre-Contingency state indicates any of the following:

- Actual flow through a Facility is above the Facility's applicable Rating for a time period longer than deemed acceptable.
- Actual bus voltage is outages applicable System Voltage Limits" for a time period longer than deemed acceptable.
- A stability limit established to prevent instability without a Contingency is exceeded for a time period longer than deemed acceptable.
- A stability limit established to prevent the Contingency from resulting in instability is exceeded for a time period longer than deemed acceptable.

The calculated post-Contingency state indication persists for any of the following:

- Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur
- Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur
- Defined stability performance criteria are not met

SOL Exceedance - Next Contingency

An Operating condition or analysis result characterized by any of the following, as determined in Operational Planning Analysis (OPA):

The pre-Contingency state indicates any of the following:

- Flow through a Facility is above the Facility's normal Rating
- Bus voltage is outages normal System Voltage Limits
- A stability limit established to prevent instability without a Contingency is exceeded
- A stability limit established to prevent the Contingency from resulting in instability is exceeded

The calculated post-Contingency state indication persists for any of the following:

- Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur
- Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur
- Defined stability performance criteria are not met"

These changes will allow the definition to work in the pre-Contingency state as envisioned by the SDT while also clarifying that an SOL exceedance after a contingency occurs in real time only exists if the actual flow or the actual voltage (i.e. the new pre-Contingency state) is outside of the applicable limit for an applicable period of time. In addition, these changes provide the needed clarity for post-Contingency situations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
See our comments under Question 7.	
Likes 0	
Dislikes 0	
Response	
See response under Question 7.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	

Answer	No
Document Name	
Comment	

NIPSCO is not in agreement that an SOL Exceedance has occurred if the flow is over a rating for an "Acceptable duration" being the time allowed for the next emergency rating. We do agree that an exceedance would occur if outside that "acceptable duration". In the explanation the Standards Develop Team states that "any PERSISTENT exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an acceptable duration." The word "persistent" and the idea that there is NOT an "acceptable duration" for the flow to go over the Normal Rating seem to contradict. Also the SOL Performance Summary on page 11 of the Rationale document states, "Pre-Contingency flow in this range (between normal and first emergency) for longer than 4 hours is not acceptable." How does this fit the explanation? Is 4 hours the acceptable duration? And if it is not acceptable to go beyond the 4 hours then we assume less than 4 hours is acceptable. If so, how can an SOL exceedance be acceptable since by the SDT definition for a flow above normal there is an SOL exceedance? We believe the MISO definition for Pre-Contingency as it relates to Facility Ratings is better. The MISO definition is as follows:

SOL Exceedance Based on Real-Time Flows

A. Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.

B. Actual steady state flow on a BES Facility is above the Normal Rating, but below the next Emergency Rating, for longer than the time frame of the next Emergency Rating.

C. Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

D. Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

E. Any established stability Limit (non-IROL) is exceeded for longer than the 30 minutes or defined by operating guides.

Likes 0	

Dislikes 0	
Response	

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	

Comment

MidAmerican Energy Company (MEC) re-iterates our disagreement with the proposed definition of SOL exceedance. We note the SDT's reluctance to incorporate our original comments and suggested changes submitted during the August 2016 commenting period.

- The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause unintended consequences on large spectrum of the Industry's participants.
- The first issue with the SDT's proposed definition of the SOL exceedance is that it would expose TOPs and RCs to unnecessary compliance risk. Significant resources for each TOP's/RC's organization would be required to meet the higher compliance administrative burden.
- The second issue is the definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, MEC believes the definition could delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. MEC believes that a potential unintended outcome to avoid the administrative burden would be to operate in an unnecessarily conservative operation

mode. The SDT has downplayed existing NERC standards that already currently require system operator training, tools, and processes to trigger the implementation of Operating Plans, including SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while respecting existing limitations of existing transmission infrastructure and human resources that operate this infrastructure. In other words the *SOL exceedance definition should be focused on defining what is considered to be unacceptable operation rather than what should be good operating practice based recommendable operation*.

Therefore, MEC recommends the SDT defer voting/ballots on this item until such time that the following tasks are completed:

- Perform comparative analysis of existing SOL definitions nation-wide, in order to get an informed insight as to where majority of industry's participants stand on this definition.
- Perform analysis of additional staffing resources and tools that would be needed to implement proposed definition.
- Outline and assess compliance driven administrative burden that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.
- Evaluate a risk of overwhelming and distracting real-time operations people with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.
- Assess the potential impact of outages with the implementation of the proposed SOL definition. The combination of the proposed SOL definition and operational outages could significantly constrain business in the industry associated with the industry's inability to approve and perform numerous scheduled outages (with many of them mandated by other NERC standards). The conservative definition of SOL exceedance would simply make it impossible for many of these outages to proceed without causing SOL exceedances.
- Assess the impact that the proposed definition would have on efficiency of market operations and associated cost.

MEC *recommends the SDT reconsider adoption of the current SOL exceedance in effect in the MISO Reliability footprint*. This is based on the following advantages of the MISO definition when compared with the SDT's proposed definition. The MISO definition:

- *Is more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
- *Would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
- Would provide *comparably reliable operation* of power systems.
- Is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".
- Would *prevent potential increased* market operations costs.
- Would provide *more clarity and avoid ambiguity and interpretation issues*.
- Is more efficient for small entities that don't have advanced tools and other resources, including, but not limited to staffing and support personnel.

The current MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

- *Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.*
- *Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.*
- *Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.*

- *Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.*
- *Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.*
- *Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*
- *Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*
- *Rationale for MEC Comments and Recommendation*
- The SDT limited its vision of this subject to the Project 2014-03 Whitepaper**.** The Whitepaper was product of a small subset of subject matter experts. The original version of the NERC White Paper (from May 2014) was more objective and referenced the use of post-contingent action plans to address projected post-contingent issues. Subsequent versions of the NERC White Paper (revision of January 2015) weren't presented to industry, weren't approved by the Industry. More industry participant input responsible for implementing the real-time SOL exceedance definition is still needed.
- The SDT proposed definition of the SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar. The actual, pre-contingency SOL Exceedance is a real-time condition exceeding the equipment's rated capabilities, while the calculated, post-contingency risk of SOL Exceedance requires another event to happen in order to become real and actual exceedance issue.
- Both pre-contingent and post-contingent types of exceedances require and should trigger implementation of a control action from the Operating Plan. However, implementation should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability.

MEC comments on specific "components" from the SDT's document:

Component #3 – *The pre-Contingency state indicates: … Actual flow through a Facility is above the Facility's **Normal** Rating*

- Persistent should be removed as ambiguous and not auditable. The SDT determined that any persistent exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an acceptable duration. MEC disagrees with the SDT's insistence on using Normal Rating and recommend the use of Emergency Rating. The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses *no reliability repercussions as long as the flow on facility is returned below normal rating during time that was assigned for the emergency rating*. Transmission operators have used emergency ratings for many years and that fact should be correspondingly recognized in the SOL exceedance definition.
- The SDT's rationale to use Normal Rating in order to "trigger implementation of Operating Plan" is confusing. TOPs understand the limitations associated with the use of Emergency Rating and their obligation to return the flow below Normal Rating within specified time-frame. Hard-coded SCADA based operational alarms will trigger implementation of Operating Plan. Therefore, it is unnecessary to adopt a conservative definition of SOL exceedance in order to "remind" TOPs and RCs of their well understood obligation to return flow under Normal Rating in specified time-frame.
- Although the SDT stated that the their goal is to improve clarity and eliminate ambiguity they increase ambiguity and open another issue of interpretation by introducing the term **"**persistent exceedance of a Normal Rating". The time of exceedance has to be clearly specified in this component. Otherwise, how will entities, including Auditors, measure "persistency" of exceedance?
- The proposed, conservative definition could cause undesirable consequences in terms of administrative compliance burden and an unnecessarily increase the cost of market operations while providing marginal benefit to system reliability. TOPs/RCs are already under NERC obligation to protect facilities on a contingency basis, which will consequently protect that facility against real-time flow exceedances.

MEC recommends the following definition superior alternative:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***

- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Component #4 – *The pre-Contingency state indicates: … Actual bus voltage is outside normal System Voltage Limits*

- MEC disagrees with the SDT’s insistence on using Normal System Voltage Limits and recommend using Emergency Voltage Limits. Our arguments regarding the Component #4 are similar to our comments concerning the Component #3.
- The technical rationale for our recommendation is based on the fact that TOPs/RCs do operate their systems within normal voltage limits during vast majority of the time. However, there are rare instances when sudden events and changes to operating conditions, or periods during switching long transmission lines, require use of emergency voltage limits. That is why *SOL exceedance definition should be focused on what is considered to be unacceptable operation rather than what should be recommended operation*. Again, the proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden.

MEC recommends the following definition:

- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

Component #6 – *The pre-Contingency state indicates: … A stability limit established to prevent the*

Contingency from resulting in instability is exceeded

- The SDT differentiated between stability limits occurring without contingency and stability limits that are contingency based and conditioned. The SDT rational doesn’t justify the existence of two components related to stability limits.

- The physical nature of the stability limits is best addressed within individual Operating Plans. Therefore, there is no need to separate the different natures of stability problems within the definition of a SOL exceedance. This is an unnecessary complication and could be resolved by merging two subcomponents into the one.
- The proposed definition does not recognize time-frame associated with exceedances of established stability limits. If not recognized this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%).

We recommend the following definition:

- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***

Component #7 – *The calculated post-Contingency state indicates: … Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*

- The SDT provided clarification of their position by pointing out the (Project 2014-03 Whitepaper) two highlighted items in the diagram. The portion highlighted in yellow, according to the SDT's explanation) "is considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan".
- Please note the original version of the NERC White Paper (from May 2014) stated that "Post-contingency flow in this range is not acceptable unless Operating Plan address reliability impact so that it has localized impact". Subsequent versions of the NERC White Paper (revision of January 2015) introduced a statement that "Post-contingency flow in this range is not acceptable". This revision wasn't presented to the industry, and never approved by the Industry.
- The SDT's proposed definition of the post-Contingency flow SOL exceedance fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar.

- Both types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability.
- The portion of the definition that states, *"…or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur"* is intended to address the operating state highlighted in light blue. This portion of the definition will cause industry implementation and compliance issues. It introduces ambiguity and confusion. Because TOPs/RCs would be faced with hard and sometimes impossible task to determine what is actually "sufficient time" for any specific set of operational circumstances. This time may depend on unit ramp rates along with efficiency and speed of congestion management procedures (such as LMP binding). This could impose significant market operations costs, while providing marginal reliability benefits.

MEC recommends the following definition:

- *Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.*

Rationale for using Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the concept of post-contingent action plan. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating.* It's important to note that the Post-contingency action plans are NOT a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.
- MEC recommends a Post-contingency action plan developed by the TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

- Therefore, MEC would not consider a SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes without associated post-contingency action plan.

- MEC recognizes that there may be situations when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this fashion and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

The SDT's concept insists on the concept "highest Emergency Rating". The MEC alternative definition is based on the concept of "post-contingency action plan". MEC recognizes it might be argued that the TOP has to establish a new Short Emergency rating in contrast to agreeing with its RC on post-contingency action plan. Issuing a new Short Term Emergency rating should be considered as a legitimate alternative. However, there are practical obstacles to issuing higher emergency ratings (or "Load Shed Rating"). The Industry must obtain manufacturer confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment (breakers, switches, wave traps, CTs conductors, all transformers components etc.). The majority of manufacturers aren't willing to provide such data. Therefore, for practical reasons, short-term ratings based on manufacturers' data are difficult to corroborate. Consequently, each TOP and RC would need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team removes the term "Operational Planning Analysis (OPA)" from the SOL Exceedance definition. From our perspective, we feel that the SOL Exceedance Definition should be applicable to only an actual SOL Exceedance instead of focusing on a potential exceedance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

IRC is concerned that the use of the term "acceptable levels" in the first and second bullets under the description of the "calculated post-Contingency state" is unclear as to which entity—the responsible entity or the compliance authority—determines what level is "acceptable." Although the IRC believes the responsible entity should be the entity that determines the appropriate level, IRC has no consensus on appropriate substitute language at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Great River Energy does not agree with the proposed definition of SOL exceedance for the following reasons.

- The SDT's proposed definition of the SOL exceedance would expose a large number of operating entities, both TOPs and RCs, to increased compliance risk through additional administrative burden with no foreseen benefit to reliability.
- The definition should allow for a maximum time the limit can be violated, similar to the approach currently in place with Interconnection Reliability Operating Limits. This would allow time for the execution of responses either through automated mechanisms or System Operator actions to mitigate the system condition. NERC currently defines Emergency Rating as a limit, which can be exceeded for a finite period, as specified for a facility by its equipment owner. Current practices leverage the use of Emergency Ratings in many operation and planning activities, and shifting to a more stringent definition could create a significant compliance burden.

The proposed definition fails to consider the validity of calculated post-contingent values. Applicable entities will soon be held accountable with the quality of developing Real-time Assessments, as required in NERC Reliability Standards IRO-018-1(i) and TOP-010-1(i). These assessments help identify real actions that must be implemented in order to alleviate potential system problems. Often these problems are identified through N-1 contingencies, although could be identified through multiple level "tower" contingencies accounting for Facilities that are located on the same transmission infrastructure. Violating limits associated with these limits, while concerning, may not pose an immediate threat to system reliability. The definition should narrow the exceedance identification process to only real, pre-contingent values.

- We suggest and recommend *that SDT consider adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint*, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:
- It is much more realistic in recognizing existing transmission infrastructure and human resources allocated to operate such an infrastructure
- It would provide for significantly less administrative compliance burden on numerous Industry's entities as related to providing evidence to meet the current definition.
- It would provide comparable reliability in the operation of the transmission system with a substantial benefit of less administrative burden.
- It is based on the physical limitations of various components of transmission facilities as opposed to being based on "intention to trigger implementation of Operating Plan".
- It provides more clarity and avoids ambiguity and interpretation issues.
- It is much more acceptable to vast majority of Industry participants, especially smaller TOPs

As a reference to the SDT, a MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following seven conditions:

- Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.
-
- Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.
- Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.
- Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.
- Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.

- Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.
- Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.
- Great River Energy would like to emphasize the difference between the above definition and the SDT's proposed definition as it relates to the concept of a post-contingent action plan. The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used while the normal congestion management processes are attempting to return the projected post contingent flow within a longer-term rating for a specified amount of time. An SOL exceedance should not exist if a post contingent action plan has been identified and is in place to address the contingency were it to occur. It should only exist if no plan has been formulated within the specified time frame which for MISO members has been identified as 30 minutes.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

We do not believe it is necessary that NERC define SOL Exceedance. However, if there is going to be a definition we believe a simple definition for Real-time operations is best.

We suggest the following definition:

SOL Exceedance - An operating condition, as determined in Real-time Monitoring, where a System Operating Limit is exceeded.

An exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. Predicted exceedances, such as those identified through OPAs and RTAs, may or may not occur as they are just that, predicted. Predicted exceedances should not be defined and subject to the stringent set of limitations and requirements that SOL Exceedances should be. Furthermore, how predicted exceedances are identified, assessed, operationally planned for and mitigated should be the responsibility of the Reliability Coordinator. Therefore, any such definition for predicted exceedances should remain in the respective RC's SOL methodology.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe the definition should allow for a maximum time the limit can be violated, similar to the approach currently in place with Interconnection Reliability Operating Limits. This would allow time for the execution of mitigative responses either through automated mechanisms or System Operator actions. NERC currently defines Emergency Rating as a limit, which can be exceeded for a finite period, as specified for a facility by its equipment owner. Current practices leverage the use of Emergency Ratings in many operation and planning activities, and shifting to a more stringent definition could create a significant compliance burden. 2. We believe the proposed definition fails to consider the validity of calculated post-contingent values. Applicable entities will soon be held accountable with the quality of developing Real-time Assessments, as required in NERC Reliability Standards IRO-018-1(i) and TOP-010-1(i). These assessments help identify real actions that must be implemented in order to alleviate potential system problems. Often these problems are identified through N-1 contingencies, although they could be identified through multiple level “tower” contingencies accounting for Facilities that are located on the same transmission infrastructure. Violating limits associated with these limits, while concerning, may not pose an immediate threat to system reliability. The definition should narrow the exceedance identification process to only real, pre-contingent values.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No

Document Name	
Comment	

Entergy strongly disagrees with the definition as written.

The "pre-Contingency" state does not include a statement regarding time. If an entity using time dependent emergency ratings it should only be an exceedance if the actual flow through a facility is above the Facility's normal rating for a period of time greater than the timeframe of the emergency rating. The definition of the post-contingency state does take into account emergency ratings but they are essentially useless if by definition the instance after the contingency occurs and now you move into the next pre-contingency state you will immediately have an SOL exceedance.

In addition, the post-contingency state mentions the term "sufficient time" but doesn't describe what "sufficient time" time is. This leaves the definition ambiguous.

Entergy believes you should adopt the MISO definition of SOL exceedance as follow.

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***
- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***
- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***
- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***
- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

• ***Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to "Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded."	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy requests further clarification on the rationale behind the differences in criteria between pre-Contingency, and post-Contingency. As proposed, 'pre-Contingency' criteria for exceedances are above 'normal' ratings/limits, whereas 'post-Contingency' criteria for exceedances being 'above the highest/lowest' rating/limit. We feel that the rating/limit should be the same for both, and propose that the pre-Contingency criteria should also be for 'above the highest/lowest' rating/limit.

Some ambiguity exists with the use of "Normal Rating". It is possible that an entity could interpret the use of "Normal Rating" to include all ratings. We recommend the drafting team consider adding language that explains that a "Normal Rating" is defined by the entity's SOL Methodology.

- *"Actual flow through a Facility is above the Facility's Normal Rating (as defined by entity's SOL Methodology)"*

Also, there appears to be some inconsistency between the text of the SOL Exceedance definition, and the SOL Performance Summary table found on page 11 of the SOL/SOL Exceedance Rationales document. The table implies that an SOL Exceedance can occur within the 1-hr rating range. Was this the drafting team's intent? It is acknowledged that action is needed if the Exceedance occurs within the 1-hr ratings range, but does the drafting team contend that an SOL Exceedance can occur even if you are still in that 1-hr rating.

Lastly, The definition does not address temporary conditions. What happens if you have a fault and it drags your bus voltage down long enough to pick up and alarm, and then restores. Would that be an exceedance according to the proposed definition? We recommend that the drafting team include language that outlines how long an SOL may be exceeded in the RTA before a Mitigation Plan should be developed. We suggest that the drafting team insert language recommending that an SOL Exceedance has not occurred until the SOL has been exceeded for a period of 30 minutes or longer.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
The proposed definition of SOL Exceedance does not consider the concept of timeframes on Facility Ratings. Specifically, the SOL Performance Summary on page 5 of the System Operating Limit Definition and Exceedance Clarification whitepaper from Project 2014-03 indicates that Pre-Contingency flow between a Normal Rating (24 hour rating) and a higher Emergency Rating with an associated timeframe (4 hour in the specific example) is not an SOL exceedance until flow exceeds both the Normal Rating (24 hour rating) and the time limit associated with the higher limit (again, 4 hours in this specific example). The proposed definition of SOL Exceedance would consider Pre-Contingency flow above the Normal Rating (24 hour rating) to be an SOL Exceedance irrespective of any time based higher rating.	

For the Pre-Contingency state, actual flow through a Facility above its Normal Rating should not be an SOL Exceedance unless the actual flow through the Facility stayed above the Normal Rating for a duration longer than the timeframe associated with the next rating. NERC standard TOP-001-3 R14 states that “Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment”. Per the definition of SOL Exceedance TOP’s will be required to mitigate flows going above normal rating all of the time even if the facility has a valid higher rating that allows flows to be above Normal Rating for a defined period of time. While the system operators will act to reduce flows to below the normal rating an SOL Exceedance should not be defined to occur until the defined period of time for the next higher rating has been exceeded. Defining an SOL Exceedance to occur whenever the normal rating is exceeded regardless of timeframe creates a compliance burden on real time operations staff that will reduce reliability due to the distractions associated with creating compliance documentation.

For the post-Contingency state, it should be made clear that monitoring Normal Ratings for contingency analysis is not required. Instead, as depicted in the SOL Performance Summary on page 5 of the System Operating Limit Definition and Exceedance Clarification whitepaper and on page 11 of the NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale document, having a long term Emergency Rating of sufficient duration to allow for a reduction in flow to below the Normal Rating would allow for monitoring to Emergency Ratings during contingency analysis. Requiring TOP’s to monitor contingency analysis results for post contingent conditions that exceed Normal Ratings will create undue burden on system operators as well as on the contingency analysis programs. In addition, setting the threshold lower than what is currently used may reduce the usage of the transmission system. Due to the significant increase in the volume of reported contingency violations which will need to be sorted through and contemplated. In fact, some contingency analysis tools have a finite number of contingency violations that can be reported and depending on the relative severity of contingent violations, will likely result in not reporting valid post-contingent violations of emergency limits which have a much more significant impact on reliability.

Often times load shed is used as a mitigation plan when flow on a facility is above the highest Emergency Rating however implementing pre-contingent load shed to mitigate an SOL Exceedance may not be prudent all of the time since load shed may occur when the contingency happens. In addition, the impact of SOL Exceedance is local in nature. A TOP should have the ability to weigh the risks/benefits associated with implementing load shed vs risking a localized impact for a postulated post-contingent condition without having to factor in SOL Exceedance compliance considerations. The transmission system is much too dynamic to be overly prescriptive. Specifically, with the proposed definition of SOL Exceedance, standard TOP-001-3 R14/R15 may not explicitly allow for TOP’s to not implement pre-contingent load shed if post contingent operation is above the highest Emergency Rating. The Project 2014-03 Whitepaper clearly specified that pre contingency load shed may not be necessary or appropriate. Absent any modifications to TOP-001-3 the proposed SOL Exceedance definition

may require pre-contingent load shed actions. If the definition is used as currently proposed then TOP-001-3 should also be revised to add clarification that a post contingent SOL Exceedance is acceptable as long TOP has a viable Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees with the SDT that a definition for SOL Exceedance is needed to support the updated standards. We agree with all components of the definition with the exception of components #3 and #4 – exceeding normal facility ratings or normal voltage limits. Should exceeding the normal facility rating or normal voltage be the trigger for all the reporting requirements included in these updated standards. Most TOPs can exceed their normal facility ratings and normal voltage limits without any adverse effects on the system. In fact, these TOPs have emergency facility ratings and emergency voltage limits to give operators the time to take corrective actions in response to an event that would cause these normal ratings and limits to be exceeded. It seems unnecessarily burdensome to ask TOPs and RCs to report and document these events when they pose no risk to reliability. Conversely, exceeding emergency ratings and limits is definitely impactful to the reliability of the BES. It is appropriate to expect a higher threshold of reporting and documentation for these events.	

With the proposed definition, SDT putting a huge compliance burden on to TOPs and RCs for no apparent reliability impact. New definition require TOP to notify their RC, every time the real time flow or the voltage goes outside the normal range and make a log entry for compliance purposes. Manitoba Hydro believes that the SOL Exceedance definition should reflect the more sever conditions than the normal rating. For an example, due to absence of NERC definition for SOL Exceedance, MISO members developed definition for the SOL Exceedance. Like the proposed NERC definition, MISO SOL Exceedance definition also covers the real-time condition and the projected post contingency condition. According to MISO definition, SOL exceedance occurs whenever the real-time flow goes above the highest Emergency rating or the real-time voltage goes outside the emergency voltage limits. Manitoba Hydro support MISO's approach of managing SOL exceedance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not agree with the proposed definition of SOL Exceedance and believes that a definition is not necessary. If you take into consideration the FERC-referenced, NERC SOL Whitepaper coupled with the work the SDT has done to provide the industry with a clear and concise proposed definition to the System Operating Limit (SOL) term, a formalized definition to SOL Exceedance is not warranted.	

Furthermore, we believe that the proposed definition to SOL Exceedance is problematic and confusing with potential operational and compliance implications. We are concerned that the SDT definition and application of the term "stability limits" differs from the NERC approved glossary definition of "Stability Limits". This term, "Stability limit" is also used in the NERC SOL Whitepaper. CenterPoint energy urges the SDT to have further discussions and considerations towards the use of "stability limits" for proper alignment with the NERC defined term as well as how the term is used in the NERC SOL Whitepaper for clear representation to the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
See responses to Glencoe Light and Power Commission.	

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

Hoosier Energy strongly disagrees with the proposed definition of SOL exceedance. Hoosir supports the following:

1. The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause **huge unintended consequences on large spectrum of the Industry's participants**.

2. The first major problem with the SDT's proposed definition of the SOL exceedance is **that it would expose a large number of TOPs and RCs to compliance risk unless enormous resources and efforts are added within each TOP's/RC's organization to keep up with (an order of magnitude) higher compliance administrative burden**.

3. The second major problem is that this definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, we believe the definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. We believe that a potential unintended outcome to avoid the administrative burden is operating **in an unnecessarily conservative operation.** We believe the SDT has ignored a fundamental fact that the implementation of Operating Plan, even in current industry's practice, is already being triggered by existing mechanisms, such as SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

4. The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and**

human resources that operate this infrastructure. In other words the *SOL exceedance definition should be focused on defining what is considered to be* ***unacceptable operation*** *rather than what should be* ***good operating practice based recommendable operation***.

Therefore, we strongly **recommend that the SDT defers voting/ballots** on this item until such time that the following tasks are completed:

- **Perform comparative analysis of existing SOL definitions nation-wide**, in order to get an informed insight as to where majority of industry's participants stand on this definition.

- **Perform analysis of additional staffing resources and tools** that would be needed to implement proposed definition.

- **Outline and assess compliance driven administrative burden** that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.

- **Evaluate a risk of overwhelming and distracting real-time operations people** with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.

- **Assess the impact of significantly constraining business in the industry** associated with the industry's **inability to approve and perform numerous scheduled outages** (with many of them mandated by other NERC standards), as this conservative definition of SOL exceedance would simply make impossible many of these outages to proceed without causing SOL exceedances.

- Assess the impact that the proposed definition would have **on efficiency of market operations and associated cost**.

We re-iterate our ***recommendation that SDT re-considers adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint***, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:

1. It is *much more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
2. *It would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
3. It would provide *comparably reliable operation* of power systems.
4. It is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".

5. It would *prevent potentially huge increase of cost* of market operations.

6. It provides *more clarity and avoids ambiguity and interpretation issues*.

7. It is *much more acceptable to vast majority of Industry participants* as opposed to relatively small subset of industry participants that can afford use of advanced tools and other resources, including, but not limited to staffing and support personnel.

MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***

- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***

- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

- ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***

- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

- ***Projected post-Contingent voltage on a BES Facility is less than the Emergency low voltage limit for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

See the response to Q7.	
Likes 0	
Dislikes 0	
Response	
See the response for Q7.	
Michael Jones - National Grid USA - 1,3,5	
Answer	No
Document Name	
Comment	
Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to "Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA believes that a TOP should be able to exceed a Normal Rating while utilizing an Emergency Rating (with a time-dependency) without logging an SOL Exceedance or notifying their RC of the actions taken (the action taken was to use an Emergency Rating). Using an Emergency Rating for the appropriate amount of time has no impact to system reliability and is using the “applicable” rating as identified in the NERC SOL Whitepaper.

Given the drafting team’s SOL Exceedance proposal, a TOP would have to document their initiation of an Operating Plan and call their RC each time a Normal Rating is exceeded. BPA believes that this is an undue burden on the TOP and their RC and that the use of an Emergency Rating is normal operating procedure, not an SOL Exceedance.

BPA proposes this definition for SOL Exceedance:

An operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring, Real-time Assessments (RTA) or Operational Planning Analysis (OPA):

The pre-Contingency state indicates any of the following:

- *Actual flow through a Facility is above the Facility’s highest Emergency Rating, or above an Emergency Rating for longer than the associated time*
- *Actual bus voltage is below the System Voltage Limit*
- *Actual bus voltage is above the highest System Voltage Limit, or the actual bus voltage is above a time-dependent System Voltage Limit for longer than the associated time*
- *A stability limit established to prevent instability without a Contingency is exceeded*

- *A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The calculated post-Contingency state indicates any of the following:

- *Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*
- *Bus voltage is outside the highest or lowest System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to established acceptable levels should the Contingency occur*
- *Defined stability performance criteria are not met*

The proposed NERC defined term System Voltage Limit is used in the proposed definition of SOL Exceedance. System Voltage Limit is in a separate NERC posting out for comment, but since BPA will be proposing a revision to the definition of System Voltage Limit, BPA has used this revised definition in the comments submitted by BPA on the SOL Exceedance definition. Subsequently, BPA thinks it is relevant to share this revised definition with the drafting team now.

BPA proposes the following revisions to the definition of System Voltage Limit:

"The minimum steady-state voltages (both pre-Contingency and post-Contingency) that provide for acceptable System performance. The maximum steady-state voltages based on equipment ratings (both Normal Rating and Emergency Rating) that provide for acceptable System performance."

When addressing the post-Contingency bus voltage in the SOL Exceedance, the use of "emergency" is redundant given BPA's revised definition of System Voltage Limit because "Emergency Rating" is included in the revised definition.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	No
Document Name	
Comment	

Glencoe re-iterates our strong disagreement with the proposed definition of SOL exceedance. We express our disappointment with SDT's reluctance to incorporate our original comments and suggested changes that we submitted during the August 2016 commenting period.

The SDT failed to assess and recognize that the proposed SOL exceedance definition will cause **huge unintended consequences on large spectrum of the Industry's participants**.

The first major problem with the SDT's proposed definition of the SOL exceedance is **that it would expose a large number of TOPs and RCs to compliance risk unless enormous resources and efforts are added within each TOP's/RC's organization to keep up with (an order of magnitude) higher compliance administrative burden**.

The second major problem is that this definition is driven by SDT's belief that the definition would "trigger implementation of Operating Plan". However, we believe the definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. We believe that a potential unintended outcome to avoid the administrative burden is operating **in an unnecessarily conservative operation.** We believe the SDT has ignored a fundamental fact that the implementation of Operating Plan, even in current industry's practice, is already being triggered by existing mechanisms, such as SCADA operating alarms, RTCA results, principles of reliable operations and high quality operator's training.

The role of NERC adopted definition of SOL exceedance definition, in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human**

resources that operate this infrastructure. In other words the *SOL exceedance definition should be focused on defining what is considered to be* ***unacceptable operation*** *rather than what should be* ***good operating practice based recommendable operation***.

Therefore, we strongly **recommend that the SDT defers voting/ballots** on this item until such time that the following tasks are completed:

Perform comparative analysis of existing SOL definitions nation-wide, in order to get an informed insight as to where majority of industry's participants stand on this definition.

Perform analysis of additional staffing resources and tools that would be needed to implement proposed definition.

Outline and assess compliance driven administrative burden that the proposed definition would impose on numerous entities in terms of providing an evidence of compliance that they initiated an Operating Plan for each single event of SOL exceedance.

Evaluate a risk of overwhelming and distracting real-time operations people with a burden of significantly increased communication requirements associated numerous instances of marginally relevant localized SOL exceedances.

Assess the impact of significantly constraining business in the industry associated with the industry's **inability to approve and perform numerous scheduled outages** (with many of them mandated by other NERC standards), as this conservative definition of SOL exceedance would simply make impossible many of these outages to proceed without causing SOL exceedances.

Assess the impact that the proposed definition would have **on efficiency of market operations and associated cost**.

We re-iterate our ***recommendation that SDT re-considers adoption of the SOL exceedance that is currently in effect in MISO Reliability footprint***, based on the following advantages of the MISO definition when compared with the SDT's proposed definition:

It is *much more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*

It would provide for significantly less administrative burden on numerous Industry's entities related to providing evidences of compliance.

It would provide *comparably reliable operation* of power systems.

It is *based on physical limitations of various components of transmission facilities* as opposed to being based on "intention to trigger implementation of Operating Plan".

It would *prevent potentially huge increase of cost* of market operations.

·It provides *more clarity and avoids ambiguity and interpretation issues*.

It is *much more acceptable to vast majority of Industry participants* as opposed to relatively small subset of industry participants that can afford use of advanced tools and other resources, including, but not limited to staffing and support personnel.

MISO Reliability footprint wide SOL Exceedance occurs if system operating state indicates any of the following:

Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.

· ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.

The SDT determined that any **persistent** exceedance of a Normal Rating should be regarded as an SOL exceedance, even if the exceedance occurs for an **acceptable duration**. We disagree with SDT's insistence on using Normal Rating **and re-iterate our recommendation to use Emergency Rating.** The technical rationale for our recommendation is based on the TOP rating methodology which considers all limiting factors for transmission facilities and assesses ***no reliability repercussions as long as the flow on facility is returned below normal rating during time that was assigned for the emergency rating***. In the matter of fact, this is one of main reasons that transmission operators are given an emergency ratings and that fact should be correspondingly recognized in the SOL exceedance definition.

The SDT's rationale to use Normal Rating in order to "trigger implementation of Operating Plan" is confusing. TOPs are perfectly aware of the limitations associated with the use of Emergency Rating and their obligation to return the flow below Normal Rating within specified time-frame**. Furthermore, hard-coded SCADA based operational alarms will trigger implementation of Operating Plan. Therefore, it is absolutely**

unnecessary to adopt conservative definition of SOL in order to "remind" TOPs and RCs of their well understood obligation to return flow under Normal Rating in specified time-frame.

Secondly, although SDT stated that the their goal is to improve clarity and eliminate ambiguity they increase ambiguity and open another issue of interpretation by introducing the term **"persistent** exceedance of a Normal Rating". The time of exceedance has to be clearly specified in this component. Otherwise, how will entities, including Auditors, measure "persistency" of exceedance?

The proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden and unnecessary increase of the cost of market operations while providing marginal benefit to system reliability as TOPs/RCs are under obligation to protect facilities on a contingency basis, which will consequently protect that facility against real-time flow exceedances.

We recommend the following definition:

· ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***

· ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

Component #4 – *The pre-Contingency state indicates: … Actual bus voltage is outside normal System Voltage Limits*

We disagree with SDT's insistence on using Normal System Voltage Limits and recommend using Emergency Voltage Limits. Our arguments regarding the Component #4 are similar to our comments concerning the Component #3.

The technical rationale for our recommendation is based on the fact that **TOPs/RCs do operate their systems within normal voltage limits during vast majority of the time**. However, there are rare instances when sudden events and changes to operating conditions, or periods during switching long transmission lines, require use of emergency voltage limits. That is why *SOL exceedance definition should be focused on what is considered to be unacceptable operation rather than what should be recommended operation*. Again, the proposed, conservative definition would cause undesirable consequences in terms of administrative compliance burden.

We recommend the following definition:

Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.

Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.

Component #5 – *The pre-Contingency state indicates: … A stability limit established to prevent instability without a Contingency is exceeded*

Component #6 – *The pre-Contingency state indicates: … A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The SDT apparently concluded that there is a reason to differentiate between stability limit occurring without contingency and stability limit that is contingency based and conditioned. We do not see reason that would be strong enough in order to justify existence of two components related to stability limits.

We believe that the physical nature of the stability limits is best addressed within individual Operating Plans. Therefore, there is no need to separate different natures of stability problems within definition of SOL exceedance. We believe that this is unnecessary complication and could be resolved by merging two subcomponents into the one.

We also find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%).

We recommend the following definition:

· ***Any established stability limit (non-IROL) is exceeded for longer than the 30 minutes or defined by Operating Plan.***

Component #7 – *The calculated post-Contingency state indicates: … Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which there is not sufficient time to reduce the flow to established acceptable levels should the Contingency occur*

The SDT provided clarification of their position by pointing out the (Project 2014-03 Whitepaper) two highlighted items in the diagram. The portion highlighted in yellow, according to the SDT's explanation) "is considered an SOL Exceedance because this designation accomplishes the desired outcome by triggering mitigating action through the implementation of an Operating Plan".

First, we need to draw attention of the SDT that the original version of the NERC White Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability impact so that it has localized impact**". Subsequent version of the NERC White Paper (revision of January 2015) introduced statement that "Post-contingency flow in this range is not acceptable".

This revision, with a major impact, was never presented to the industry, never approved by the Industry and in our opinion was step in the wrong direction.

The SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "SOL exceedance" may easily cause an incorrect expectation that TOP/RC control action response to these two types of exceedances should be similar.

It is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability.

The portion of the definition that states, *"…or above a Facility Rating for which there is not **sufficient time** to reduce the flow to established acceptable levels should the Contingency occur"* is intended to address the operating state highlighted in light blue. **This portion of the definition will be permanent source of major troubles for the industry, from the implementation prospective**. It **introduces ambiguity and confusion, because TOPs/RCs would be faced with hard and sometimes impossible task to determine what actually is "sufficient time" for any specific set of operational circumstances**. This time might be dependent on ramp rates of the units but also on efficiency and speed of congestion management procedures (such as LMP binding). **This may also cause huge cost to market operations, while providing marginal benefits to system's reliability**.

We recommend the following definition:

Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.

Rationale for using Post-contingency action plan concept

The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating***. It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

In contrast to this, we think that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this fashion and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that it might be argued that the TOP has to establish a new Short Emergency rating in contrast to agreeing with its RC on post-contingency action plan. Issuing a new Short Term Emergency rating should be considered as a legitimate alternative, indeed. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings**) for every single piece of equipment (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc.). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data**. Consequently, each TOP and RC would need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	

It is felt that an SOL Exceedance has not occurred until both a limit and corresponding time frame have been surpassed, which is supported by the SOL whitepaper. If a Facility has a Normal Rating and corresponding 4-hour Emergency Rating, reliable operation can occur even after surpassing the Normal Rating (but still less than the Emergency Rating) for less than 4 hours. Operating in an allowed reliable state should not be an SOL Exceedance. SOL Exceedances should be to the true binding limitations of the system for purposes of consistency. This does not preclude an operator from taking action, but should not be required if reliable system operation has been determined within this range. This should be true for both pre- and post-contingent discussions as long as mitigation can take place within the allotted timeframe.

As currently written, pre-contingent and post-contingent definitions are inconsistent. A post-contingent Normal Rating exceedance that can be mitigated with its allowable timeframe would immediately become an SOL exceedance if the contingency occurs.

Suggested language as follows:

*A **binding and valid** operating condition or analysis result characterized by any of the following, as determined in Real-time monitoring, Real-time Assessments (RTA) or Operational Planning Analysis (OPA):*

The pre-Contingency state indicates any of the following:

- *Actual flow through a Facility is above the Facility's **respective rating (Normal or Emergency) longer than the allowable time defined by the TOP***
- *Actual bus voltage is outside **acceptable** System Voltage Limits **longer than the allowable time defined by the TOP***

- *A stability limit established to prevent instability without a Contingency is exceeded*
- *A stability limit established to prevent the Contingency from resulting in instability is exceeded*

The calculated post-Contingency state indicates any of the following:

- *Flow through a Facility is above the Facility's highest Emergency Rating, or above a Facility Rating for which **it is known that flow would exceed the rating longer than the respective allowable time defined by the TOP should the contingency occur***
- *Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which **it is known that the voltage would remain outside the limit longer than the respective timeframe defined by the TOP** should the Contingency occur*
- *Defined, non-limit based stability performance criteria are not met as determined by those entities with the capabilities and processes to do so*

*Valid and binding shall ensure that conditions or results flagged are of sufficient accuracy and consistency. Nuisance (i.e., intermittent alarming) conditions or results shall not be considered a binding SOL Exceedance.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	

Colorado Springs Utilities finds the Project 2014-03 SDT's rationale for what constitutes an SOL Exceedance to be compelling and reasonable. The proposed definition in question strays from the White Paper produced by that Project (and subsequently adopted as "ERO Enterprise-Endorsed Implementation Guidance") in a significant way - that of being able to fully utilize all applicable thermal ratings and associated time frames in Real-time. The purpose of SOLs is to "ensure operation within acceptable reliability criteria," and entities establish thermal SOLs, including any so-called "emergency" ratings and their attendant time limits, with those criteria in mind.

From the White Paper, "SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance." In other, other words; operating, Real-time, with MW flows above a Facility's normal/continuous thermal rating but below a time-limited "emergency" rating for a time not exceeding the applicable time-limit is acceptable system performance and, thus, not an SOL Exceedance. This is straight-forward logic, and conforms with the White Paper you reference.

TOP-001-3, R14, requires, "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." Colorado Springs Utilities believes this requirement is met, in spirit and in letter, by an entity implementing an Operating Plan to prevent exceeding the time limit imposed by any specific, applicable thermal SOL. This requirement would also be met, in spirit and in letter, by an entity recognizing that operating slightly above the normal/continuous rating (but below the time-limited "emergency" rating) will only persist for a time less than the applicable time limit due to the forecasted load curve and taking no specific action other than monitor.

Therefore, Colorado Springs Utilities requests changing the first bullet under the "pre-Contingency" list to read:

•	Actual flow through a Facility is above the applicable Facility Rating for an unacceptable time duration

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

While AEP agrees overall with the proposed definition, we are unsure of the need to include the text “Real-Time monitoring.” Unlike Real-time Assessments and Operational Planning Analysis, the phrase “Real-Time monitoring” is not a NERC glossary term. If “Real Time Assessment” is not already encompassing enough, what additional operating conditions or analysis would be brought into scope by including “Real-Time monitoring” in the definition?

AEP seeks clarity on the use of the term “calculated” relative to the post-contingency state. Nowhere in the technical justification, or as phrased in the question above, does it clarify the need to distinguish between calculated or actual post-contingency states.

Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
The addition of the definition of SOL Exceedance is necessary in conjunction with the modification of the definition of SOL.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Idaho Power agrees with the proposed definition, but recommends a wording change to the post-contingency facility rating bullet. Instead of "the Facility's highest Emergency Rating," the definition should state that flows should not exceed "the Facility's highest Emergency Rating for the operating conditions." For example, winter ratings should not be used for summer operating conditions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
We think the "or analysis result" is not necessary considering the reference to RTA and OPA. We appreciate the introduction of time to reduce the flow in the assessment of an operating condition. We suggest to reword "A stability limit established to prevent a (instead of the)	

Contingency from resulting in instability is exceeded". Also, same comment as for the SOL definition regarding the use of the non-defined term stability limit and the link with the interface concept.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the SDT's proposed definition of SOL Exceedance and with the arguments set forth in question #4 and with those set forth in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed definition makes clear the concept of SOL Exceedance as separate from an SOL.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes

Document Name	
Comment	
Thank you for your response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Comments: Texas RE generally agrees with the SDT's approach to separate the definition of System Operating Limits (SOLs) from the definition of an "SOL Exceedance." In particular, Texas RE agrees with the NERC-endorsed implementation guidance that "[i]t is important to distinguish operating practices and strategies from the SOL itself." That is to say, while SOLs are based on an entity's actual set of Facility Ratings, voltage limits, and Stability Limits monitored in pre- and post-contingency states, SOL Exceedances should reflect performance within all applicable limits over the time horizon at issue. The SDT appears to take appropriate steps to clarify that distinction.	

With these general comments in mind, Texas RE notes one area that could further enhance the new SOL and SOL Exceedance definitions. In particular, both the SOL and SOL Exceedance definitions refer to "stability limits" and do use the existing NERC "Stability Limit" definition. "Stability Limit" is currently defined as: "[t]he maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers." The SDT should consider using the existing Stability Limit definition or, alternatively, revise the definition to reflect the new SOL and SOL Exceedance definitions. At a minimum, Texas RE requests that the SDT identify the aspects of the existing Stability Limit definition that warrant using the non-defined term.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

5. Considering the explanations provided here and further explained in the definitions rationales, do you agree that the proposed SOL Exceedance definition should include this bullet item? Please explain your response and/or provide alternative language.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

Question #5 states that “If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance.” While we agree with this view, we do not believe it is obvious or apparent when looking solely at the proposed definition only. We believe any such clarity or insight should be added to the definition itself.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment	
While the intention is good, stability performance criteria are more subjective than thermal and voltage criteria. The acceptability of stability performance may vary more than that of thermal and voltage acceptability. This definition may unnecessarily invite the determination of non-compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	No
Document Name	
Comment	
Colorado Springs Utilities is not so optimistic to believe that, "If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC …" We believe it is the natural tendency of a regulatory body to enforce regulations rather indiscriminately once codified, regardless of the intent of the authors. Colorado Springs Utilities is also bemused by the presumption that entities won't take appropriate responses without a regulatory "trigger."	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	
Without stating in some way the rationale in the definition itself, it could easily be interpreted that some form of action would be required of all entities, not just those that have the capability to perform these types of studies. It is clear that the intent is not requiring real-time stability analysis tools; therefore, a clear distinction must be made to ensure this only applies to certain entities. Suggested language: *Defined,* ***non-limit based*** *stability performance criteria are not met* ***as determined by those entities with the capabilities and processes to do so***	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

abandoned the idea of creating a definition for SOL Exceedance in favor of addressing performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards.

Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	No
Document Name	
Comment	
We consider this portion of the definition as unnecessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations (which we recommend to also be merged within one clearly defined stability related bullet. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
BPA suggests that the definition spell out: "If a TOP or a RC does not use real-time tools in this manner, then this bullet of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance." An entity should not have to search for when it is applicable. BPA would like the context added to the definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
John Seelke - LS Power Transmission, LLC – 1	
Answer	No
Document Name	
Comment	
See the response to Q7.	
Likes 0	
Dislikes 0	

Response	
See the response to Q7.	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
This portion of the definition as unnecessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations (which we recommend to also be merged within one clearly defined stability related bullet. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Theresa Allard - Minnkota Power Cooperative Inc. – 1	
Answer	No
Document Name	

Comment	
See comments submitted by Glencoe Light and Power Commission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	No
Document Name	
Comment	
Including this bullet seems to put additional burden on TOP's and RC's utilizing real time tools to determine if stability criteria are being met. This may inadvertently discourage entities from implementing these types of real time tools that could help to enhance reliability. In addition, the rationale document states that "If the TOP or RC does not utilize Real-time stability tools to determine the system's response to Contingency events and to evaluate that response against defined stability performance criteria, but solely utilizes a more traditional approach for establishing stability limits (i.e., limit "values") to address system instability, then the third bullet in the post-Contingency section of the proposed SOL Exceedance definition would not apply to that TOP or RC, and the fourth bullet under the pre-Contingency section of the SOL Exceedance definition would govern stability performance." However the definition itself does not list any exclusions or state that this	

bullet is "above and beyond". The definition used in a standard should clearly state the applicability and should exclude this bullet if the SDT considers it only applicable to entities with certain tools.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Entergy believes that this bullet item is not necessary since the stability is covered in the pre-contingency part.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The proposed definition assumes each applicable entity possesses its own on-line stability tools or are actively monitoring its operating parameters to indicate the next Contingency that could result in instability. This may not always be the case. Moreover, what happens if an entity loses the availability of these tools? We believe the addition of this bullet to the definition is unnecessary, as applicable entities will likely take appropriate action to avoid the possible exceedance of a stability limit in the pre-Contingency state.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment	
Our proposed definition covers both established stability limits and stability limits determined using Real-time tools making this distinction unnecessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The proposed definition assumes each applicable entity possesses its own on-line stability tools or are actively monitoring its operating parameters to indicate the next Contingency that could result in instability. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations. Per our recommendation to utilize the MISO definition in question #4, we believe these two bullets could be combined into one clearly defined stability related condition. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well or the single definition, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
This portion of the definition isn't necessary, as it would apply to very limited number of TOPs/RCs that use real-time tools for determining defined stability performance. Established stability limits are sufficiently addressed by the third and fourth bullets under pre-Contingency operations. Those entities that use real-time stability tools should use the third and fourth bullets under pre-Contingency operations as well, with understanding that their stability limits might vary in real-time as opposed to be fixed/established.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

NIPSCO feels the use of “sufficient time” in the definition is vague. Who defines “sufficient time”? Is it the RC or the TO? Again NIPSCO likes the MISO definition as it is more descriptive. It reads as follows:

SOL Exceedance Based on Projected Post-Contingent Flows, Determined by a Real-Time Assessment

A. Projected post-Contingent loading on a BES Facility is greater than the highest emergency rating for longer than 30 minutes with **NO** agreed upon action plan that would mitigate the condition if the Contingency were to occur.

B. Projected post-Contingent voltage on a BES Facility is less than the emergency low voltage limit for longer than 30 minutes with **NO** agreed upon action plan that would mitigate the condition if the Contingency were to occur.

Likes 0	
Dislikes 0	

Response

Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak agrees that the definition of SOL Exceedance should include the item "Defined stability performance criteria are not met." However, it should be made clear to auditors that this aspect of the definition applies only to entities that use real-time tools to determine whether the system is meeting stability performance criteria or not. I.e., if a TOP or RC is not using real-time tools, but is instead using actual predetermined stability limits (limit "values") in accordance with the last two bullets in the pre-Contingency section of the proposed definition of SOL Exceedance, then the bullet in question should not apply to that TOP or RC.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
IRC agrees with including this item; however, IRC suggests clarifying that "defined stability performance criteria" refers to criteria defined by the RC in its SOL Methodology, as follows: · Stability performance criteria *defined by the RC in its SOL Methodology* are not met	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation recommends, if it is the intent of the third post-Contingency bullet to only apply to those TOPs or RCs that additionally use real-time tools to determine whether defined stability performance criteria are being met, that the bullet explicitly state this applicability criterion so as to provide clarity and avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	

Answer	Yes
Document Name	
Comment	
The definition allows TOPs and RCs to recognize that the standards are about maintaining an adequate level of system performance for all customers. Many reliability issues are not adequately captured by traditional SOL values and are best measured by other system parameters. Although ATC agrees that the inclusion of this bullet is acceptable, the term "stability" with this bullet may cause confusion for some entities. Another possible term to use is "Defined system performance criteria are met".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response
Thank you for your response. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

6. The SAR is being revised to authorize the SDT to review the existing body of Reliability Standards and NERC Glossary of terms, and where necessary, modify those standards and definitions to incorporate the new terms and/or definition(s) of SOL Exceedance and System Voltage Limit, as well as the revised definition of System Operating Limit. The SDT has identified the standards and terms they contend would benefit from this incorporation and has included them in separate documents with this posting for your review. Do you agree with the SDT's selections? If not, please explain your response.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Refer to the comments for Question 3 that identify the need for Stability Limits definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

The current definition of SOL has been the foundation of the existing suite of Reliability Standards, in addition to operating practices, since 2007. Any change in the definition of SOL and the implementation of the new definitions needs to be carefully coordinated with updates to existing standards to accommodate the revised definition.

IRC has identified the following additional four Reliability Standards that it believes should be considered for updates included in the SDT Spreadsheet:

MOD-001-2 R1.1 The requirement should be changed to acknowledge the new definition

PER-004-2 R2 The VSLs needs to be modified since they were written with the 'most limiting' of ratings to be considered. The proposed definition includes the entire universe of ratings which I don't believe was the intent of the VSLs.

VAR-001-4.1 R1 The requirement should be changed to acknowledge the new definition.

Interconnection Reliability Operating Limit Glossary of Terms Need to replace violated with exceeded.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT will consider these standards for future definition integration.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Since we don't agree that a definition for SOL Exceedance is needed, there is no need to incorporate it into these other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT	

maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe the SDT should expand their review to any reference to the phrase "limit," in the context of System Operating Limits, in the NERC Reliability Standard and NERC Glossary. This includes the addition of glossary terms like Emergency Rating, Flowgate Methodology, Rating, and Reliable Operation. 2. The scope of the SAR should also be expanded to consider the review of applicable requirements that could be retired under various Paragraph 81 criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q7.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TPL-001-4 is absent from the list. While TPL-001-4 does not explicitly mention SOLs, Table I does discuss stability limits and facility and voltage ratings.	
Likes 0	
Dislikes 0	
Response	
Because TPL-001-4 does not use the term "SOL" it was excluded from the list. Additionally, TPL-001-4 is related to planning – not to operations. The proposed definition of SOL is solely related to the limits used in the operation of the BES.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
MidAmerican agrees with the SDT's selection.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	Yes
Document Name	
Comment	
The SDT should take the opportunity of this revision to ensure that clarity exists when other standards refer to deliverables or language used in the current FAC standards. For example, CIP-002-5.1a criterion 2.6 refers to a list of facilities critical to the derivation of IROL used in FAC-014, but the current FAC-014 does not explain in any way what critical facilities are versus non-critical facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In the posted document entitled Standards Impacted by the Retirement of FAC-010-3, the SDT proposes that the associated CIP standards be modified to move away from the use of IROL facilities to determine CIP applicability.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the SDT's selections.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Glencoe agrees with the SDT’s selection	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Care should be taken on implementing this definition. Once formal (capitalized) definitions become effective, entities will use that explicitly when complying with NERC standards. For example, confusion can occur if standards incorrectly use “SOL exceedance” or “exceeding an SOL” vs “SOL Exceedance. There must be a way to ensure continuity so that the intent of the requirement is clear.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Brandon Ware - Colorado Springs Utilities - 1,3,5,6, Group Name Colorado Springs Utilities	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA appreciates your consideration of the time and effort we put into our comments and sincerely hopes that we can influence change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	
Document Name	v4 LSPT Q7 attachment SOL, SOL Exceedance comments.docx
Comment	
Due to SBS formatting limitations, the Q7 response is separately attached.	
Likes 0	
Dislikes 0	
Response	
The SDT was unable to see the comments.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	
Document Name	
Comment	
1. We believe the SDT should have included a request for comments on its proposed definition for System Voltage Limit, since this definition directly ties to the SOL definition. The references to normal and emergency in this definition do not aligned with the proposed SOL and SOL Exceedance definitions. Further guidance on what constitutes "acceptable performance" is also needed. 2. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
The SDT will address concerns with the proposed System Voltage Limit definition as part of its own ballot and comments.	
Michael Brytowski - Great River Energy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Great River Energy believes the SDT should have included a request for comments on its proposed definition for System Voltage Limit, since this definition directly ties to the SOL definition.	
Likes 0	
Dislikes 0	
Response	
The SDT will address concerns with the proposed System Voltage Limit definition as part of its own ballot and comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE and NGrid	
Answer	

Document Name	
Comment	

The definitions addressed here achieve the objective of "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."

It should be noted that the consistency in the definition of SOLs and application of SOLs to determine SOL Exceedances does not translate as a consistent, comparative indicator of reliable system performance. The contingencies applied to establish an SOL Exceedance event are bounded only by a floor of three contingencies mandated by FAC-011. OPAs and RTAs determine SOL Exceedances in accordance with the local SOL methodologies. SOL methodologies may or may not significantly expand the applicable contingencies which define SOL Exceedances. Comparing SOL Exceedances from one SOL methodology to the SOL exceedances of another SOL methodology can be a case comparing apples to oranges.

Likes 0	
Dislikes 0	

Response

The SDT agrees that the selection of Contingencies has a significant impact on the existence (or non-existence) of stability limits. For example, if the SOL Methodology considers a high number of multiple Contingencies such as breaker failure or common tower multiple Contingencies in its stability assessments, there is a higher likelihood that more stability limits and IROLs will be identified. The SDT recognizes that the selection of Contingencies also has an impact on the number of Facility Rating and System Voltage Limit exceedances that are likely to be observed in OPAs and RTA. Again, the more multiple Contingencies are included, the more exceedances are likely to be observed. However, the SDT believes that SOL exceedance as a phenomenon is not a function of an SOL Methodology.

Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	
Document Name	
Comment	
ERCOT ISO signs on to the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

The definitions addressed here achieve the objective of "bringing clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."

It should be noted that the consistency in the definition of SOLs and application of SOLs to determine SOL Exceedances does not translate as a consistent, comparative indicator of reliable system performance. The contingencies applied to establish an SOL Exceedance event are bounded only by a floor of three contingencies mandated by FAC-011. OPAs and RTAs determine SOL Exceedances in accordance with the local SOL methodologies. SOL methodologies may or may not significantly expand the applicable contingencies which define SOL Exceedances. Comparing SOL Exceedances from one SOL methodology to the SOL exceedances of another SOL methodology can be a case comparing apples to oranges. However, this project will result in the application of SOLs in the OPA and RTA being consistent regardless of disparity in the methodologies between different RCs.

Likes 0	
Dislikes 0	

Response

The SDT agrees that the selection of Contingencies has a significant impact on the existence (or non-existence) of stability limits. For example, if the SOL Methodology considers a high number of multiple Contingencies such as breaker failure or common tower multiple Contingencies in its stability assessments, there is a higher likelihood that more stability limits and IROLs will be identified. The SDT recognizes that the selection of Contingencies also has an impact on the number of Facility Rating and System Voltage Limit exceedances that are likely to be observed in OPAs and RTA. Again, the more multiple Contingencies are included, the more exceedances are likely to be observed. However, the SDT believes that SOL exceedance as a phenomenon is not a function of an SOL Methodology.

Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the approach within the currently effective FAC standards rather than address within a definition for SOL exceedance.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	

Comment

It is premature for industry to vote on FAC standards using the current definition as requested. While it would be nice to decouple the new standard and the revised SOL definition, the revised definition fundamentally impacts how the FAC standards will be implemented. Therefore, entities must vote on the NERC standard based on the expected revised SOL definition. Where the combination of the revised definition and standard would cause concerns, then industry should vote negative accordingly. The two things cannot be effectively decoupled.

Likes 0	
Dislikes 0	

Response

The SDT believes that the FAC standards work with both the currently effective definition of SOL as well as the proposed definition of SOL.

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

1. The proposed definition of SOL Exceedance, if employed, will cause confusion as to what is a violation. For example, if flow on a line goes beyond its post-contingency STE (the highest time-based rating), should it not be considered a violation as opposed to an exceedance despite the fact the contingency has not occurred? This new definition should also identify which exceedances should also be treated as violations in the interest of eliminating confusion as to what is a SOL violation vs. what is an exceedance. Alternatively, having a definition for SOL Violation may provide the required clarity.
2. The proposed definition of System Voltage Limit seems unnecessary and the associated background information causes confusion around voltage Facility Ratings vs. System Voltage limits. System voltage limits are either present to either protect system equipment from damage or to prevent instability of the system. Therefore this defined term is not needed. The background from Q3 of this comments form states, “Facility Ratings and System Voltage Limits are not determined by a “study”; rather they are inputs to the “study”. This confuses the term further as a System Voltage Limit definition further as voltage limits which are not Facility Ratings must be studied whenever system configurations are different from what has been previously studied.
3. The proposed definition for SOL must include the glossary term “Stability” definition. Use of lower-case stability with an accompanying explanation is not sufficient to allow industry to be of a common understanding. A common understanding of “Stability” is fundamental in ensuring Interconnected System Reliability. The definition of Stability must be inclusive of what could be deemed instability; this includes thermal violations would cause cascading outages.

Likes 0	
Dislikes 0	
Response	

1. Thank you for your comments.
2. System Voltage Limits are intended to respect equipment voltage ratings and to provide acceptable voltage performance for the System. The acceptable System performance referenced in the proposed definition is intended to convey that the System is expected to perform acceptably from a voltage perspective. The NERC defined term System is *"A combination of generation, transmission, and distribution components."* This term was used in the proposed definition to convey the idea that the System Voltage Limits established by the TOP in accordance with the RC's SOL Methodology are expected to be established in a manner that renders acceptable voltage performance for the System (as defined in the NERC glossary) that resides within the TOP Area. System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. (i.e., A voltage profile of 0.6 p.u. may not damage equipment; however, it is unacceptable from a System performance perspective.)
3. As is stated in the supporting document, "NERC Glossary Definitions: System Operating Limit and SOL Exceedance Rationale", *"the intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance."* The revision of the Stability Limit defined term is outside the scope of the SDT at this time. However, if the definition of Stability Limit is modified at some point in the future, the industry should consider modifying the SOL definition to include this term.

Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	
Document Name	
Comment	
Not Applicable	
Likes 0	
Dislikes 0	
Response	

A. Introduction

1. **Title:** **System Operating Limits Methodology for the Planning Horizon**

2. **Number:** FAC-010-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Planning Authority

5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:

R1.1. Be applicable for developing SOLs used in the planning horizon.

R1.2. State that SOLs shall not exceed associated Facility Ratings.

R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.

R2.2. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:

R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

R2.3.2. System reconfiguration through manual or automatic control or protection actions.

R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

R2.5. Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:

R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.

R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:

R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).

R3.2. Selection of applicable Contingencies.

R3.3. Level of detail of system models used to determine SOLs.

R3.4. Allowed uses of Remedial Action Schemes.

R3.5. Anticipated transmission system configuration, generation dispatch and Load level.

R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:

R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.

R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.

R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.

R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years~~. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.

2.4. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in

Requirement	Lower	Moderate	High	Severe
		OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.
R5	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical

Requirement	Lower	Moderate	High	Severe
(Retirement approved by FERC effective January 21, 2014.)	comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.	comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.	comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days. OR The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.	comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer. OR The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.

1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

1.2.2 Cascading does not occur.

1.2.3 Uncontrolled separation of the system does not occur.

1.2.4 The system demonstrates transient, dynamic and voltage stability.

1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

1.3.1 Cascading does not occur.

1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word "each" from the 1st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-010-3. Docket No. RM15-13-000.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Address the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement R6 to identify the Contingencies for use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

6.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall provide its SOL Methodology and any changes to the SOL Methodology prior to the effective date of the SOL Methodology, to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

8.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates it has a reliability-related need;

8.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

8.3. Each Transmission Operator within its Reliability Coordinator Area.

M8. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R8 for the current year plus the previous 12 calendar months. .

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.
R6.	N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

			qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.
R8.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through

			more than 20 calendar days but less than or equal to 30 calendar days.	8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4		Project 2015-09 – Adopt revisions to standard.	Revisions

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-~~3~~4

3. **Purpose:** -To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme".~~Project 2015-09.

B. Requirements and Measures

R1. ~~The~~Each Reliability Coordinator shall have a ~~documented~~ methodology for ~~use in developing~~establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. ~~This~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

~~**R1.**~~**R2.** Each Reliability Coordinator shall~~:~~ include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

M2. ~~Include a description of how to identify the subset of SOLs that qualify~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.3.**~~ Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as ~~IROLs.~~

3.1. ~~The~~ specified in the Reliability Coordinator's SOL Methodology ~~shall include a requirement that SOLs provide BES~~ ;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Address the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.4.~~4.1. Specify stability performance ~~consistent with~~ criteria, including any margins applied. The criteria shall include the following:

4.1.1. ~~In the pre-contingency~~ steady-state~~, the BES shall demonstrate~~ voltage stability;

4.1.2. transient~~, dynamic and~~ voltage response;

4.1.3. angular stability; ~~all Facilities shall be within their Facility Ratings and within their thermal, voltage and~~ and

4.1.4. System damping.

4.2. Require that stability limits~~. In~~ are established to meet the ~~determination of SOLs,~~criteria specified in Part 4.1 for the ~~BES condition used shall reflect current or expected system~~Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

~~1.5.~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions ~~and shall reflect~~ including any changes to ~~system~~System topology such as Facility outages~~. ~~;

~~1.6. Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

4.5. ~~Single line to~~ Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or ~~3-~~three phase Fault (whichever is more severe~~),~~) with ~~Normal Clearing, on any Faulted~~ normal clearing, or without a Fault:

- generator~~, line,~~ ;
- transmission circuit;
- transformer~~, or~~ ;
- shunt device~~.~~; or

~~1.6.1. Loss of any generator, line, transformer, or shunt device without a Fault.~~

- ~~Single~~single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

~~1.7. In determining the system's response to a~~ Any additional types of single Contingency~~, the following shall be acceptable:~~

~~[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~1.7.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~1.7.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~1.7.3. System reconfiguration through manual or automatic control or protection actions.~~

~~1.8. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

~~R2. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:~~

~~2.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~2.2. Selection of applicable Contingencies~~

5.2. ~~A process for determining which of the~~ events identified for use in determining stability limits ~~associated with the list~~, or for use in performing OPAs and RTAs.

5.3. Any types of multiple ~~contingencies (~~Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

~~2.3.~~5.4. The method for considering the Contingency events provided by the Planning ~~Authority~~Coordinator in accordance with FAC-~~014~~015-1, Requirement ~~6) are applicable for use in the operating horizon given the actual or expected system conditions.~~ R6 to identify the Contingencies for use in determining stability limits.

~~2.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~2.4. Level of detail of system models used to determine SOLs.~~

~~2.5. Allowed uses of Remedial Action Schemes.~~

~~2.6. Anticipated transmission system configuration, generation dispatch and Load level~~

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~2.7.~~6.2. Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_v.

M6. ~~The~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~R3.~~R8. Each Reliability Coordinator shall ~~issue~~provide its SOL Methodology and any changes to ~~that methodology,~~the SOL Methodology prior to the effective date of the SOL Methodology, to ~~the effectiveness of the Methodology or of a change to the Methodology, to all of the following:~~ : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~3.1.~~8.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that ~~indicated~~requests and indicates it has a reliability-related need ~~for the methodology.~~;

8.2. Each Planning ~~Authority~~Coordinator and Transmission Planner that ~~models~~is responsible for planning any portion of the Reliability ~~Coordinator's~~Coordinator Area;

~~3.2.~~8.3. Each Transmission Operator within its Reliability Coordinator Area.

~~3.3.~~ ~~Each Transmission Operator~~ Acceptable evidence that ~~operates in~~ the Reliability Coordinator ~~Area.~~

~~C. Measures~~

~~**M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~M2.~~M8. ~~The Reliability Coordinator shall have evidence it issued~~provided its SOL Methodology~~, and any changes to that methodology, including the date they were issued, in accordance~~ to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with ~~Requirement 4.~~ receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority:

~~Regional Reliability Organization~~

~~1.2. Compliance Monitoring Period and Reset Time Frame~~

~~Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last non-compliance.~~

~~**Data**~~"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.3.~~1.2. Evidence Retention:

~~The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~1.4. Additional Compliance Information~~

~~The Reliability Coordinator shall make the following available for inspection during an on-site audit~~The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by ~~the~~its Compliance ~~Monitor or within 15~~

~~business days~~Enforcement Authority to retain specific evidence for a longer period of ~~a request~~time as part of an investigation~~ upon complaint:~~.

~~**1.4.1** SOL Methodology.~~

~~**1.4.2** Superseded portions~~The Reliability Coordinator shall keep data or evidence of ~~its SOL Methodology that had been made within the past 12 months.~~

~~**1.4.3** Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.~~

~~**2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**~~

~~**2.1. Level 1:** There shall be a level one non-~~compliance ~~if either of the following conditions exists:~~

~~**2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.~~

- ~~**Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4~~with Requirements R1 through ~~R3.7 and E1~~R8 for the current year plus the previous 12 calendar months. .

~~**2.2. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:~~

~~**2.2.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.~~

~~**2.2.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.~~

~~**2.2.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.~~

~~**2.3. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.~~

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
~~R1~~R2.	~~Not applicable.~~ N/A	~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~N/A	The Reliability Coordinator ~~has a documented~~ included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use ~~in developing SOLs within~~of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area~~, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~ did not include in its SOL Methodology the method for ~~use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1~~Transmission Operators to determine the applicable owner-provided Facility Ratings to be used~~;~~ ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use~~ in ~~developing SOLs within its Reliability Coordinator Area.~~operations.

~~R2~~**R3.**	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~ .	~~Not applicable.~~The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~.	~~The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)~~The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.
~~R3~~ **R4.**	The Reliability ~~Coordinator's~~Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's SOL Methodology is missing a description of~~Coordinator failed to incorporate four or more of the ~~following: R3.1 through R3.7~~Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of

				Requirement R5 into its SOL Methodology.
~~R3.6~~**R6.**	N/A	N/A	~~N/A~~The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	~~N/A~~The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the

			Transmission Operator established.	periodicity of SOL communication.
~~R4~~R8.	The Reliability Coordinator ~~failed to issue~~provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to one of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change,~~accordance with Part 8.4 but was ~~provided to all the required entities no more~~late by less than or equal to 10 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator ~~failed to issue~~ provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to two of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology~~ accordance with Part 8.4, but was ~~provided to one or more of the required entities~~late by more than 10 calendar days ~~after the effectiveness of the change, but~~ but less than or equal to 20 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or~~to one ~~or more changes to that methodology to three~~ of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was~~ The Reliability Coordinator provided ~~to one or more of required entities~~its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days ~~after the effectiveness of the change, but~~ but less than or equal ~~to30~~to 30 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or one or more changes~~ to ~~that methodology to four~~two or more of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was provided~~ The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the ~~required entities more than30~~parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a

				requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days ~~after the effectiveness of the change~~. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

~~E.~~D. Regional ~~Differences~~Variances

~~3. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:~~

~~3.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:~~

~~3.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.~~

~~3.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7~~

~~3.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.~~

~~3.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.~~

~~3.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.~~

~~3.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.~~

~~3.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.~~

~~3.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:~~

~~3.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.~~

~~3.2.2 Cascading does not occur.~~

~~3.2.3 Uncontrolled separation of the system does not occur.~~

~~3.2.4 The system demonstrates transient, dynamic and voltage stability.~~

~~3.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~3.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~3.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~3.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~3.3.1 Cascading does not occur.~~

~~3.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
~~3~~4	~~November 19, 2015~~	~~FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.~~Project 2015-09 – Adopt revisions to standard.	Revisions

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator’s SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability

Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and

5.2.5. The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of

Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

			to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.
R5.	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6.	N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-~~2~~3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable ~~planning and~~ operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   ~~1.1. Planning Authority~~

   ~~1.2. Transmission Planner~~

   4.1.2. Transmission Operator

~~2. **Effective Date:** April 29, 2009~~

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

~~The~~

R1. Each Reliability Coordinator shall ~~ensure that SOLs, including~~ establish Interconnection Reliability Operating Limits (IROLs~~),~~) for its Reliability Coordinator Area ~~are~~in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established ~~and that the SOLs (including Interconnection Reliability Operating Limits) are consistent~~IROLs in accordance with ~~its~~it SOL Methodology.

R2. ~~The~~Each Transmission Operator shall establish ~~SOLs (as directed by its Reliability Coordinator~~System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

~~**R1.**~~**R3.** The ~~Planning Authority~~Transmission Operator shall ~~establish SOLs, including IROLs, for~~provide its ~~Planning Authority Area that are consistent~~SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. ~~The Transmission Planner shall establish SOLs, including IROLs, for its~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission ~~Planning Area that are consistent~~Operator provided its SOLs in accordance with its ~~Planning Authority's~~Reliability Coordinator's SOL Methodology.

~~**R1.** The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:~~

R4. ~~The~~Each Reliability Coordinator shall ~~provide its SOLs~~establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) ~~to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and~~ at least once every twelve calendar months.

~~1.1.~~5.2. Each impacted Planning ~~Authorities~~Coordinator within its Reliability Coordinator Area~~. For~~, the following information for each established stability limit and each established IROL~~, the Reliability Coordinator shall provide the following supporting information~~ at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

~~1.1.1.~~5.2.2. Identification ~~and status~~ of the ~~associated Facility (or group of~~ Facilities~~)~~ that ~~is (~~are~~)~~ critical to the derivation of the stability limit or IROL~~.~~;

~~1.1.2.~~5.2.3. The ~~value of the IROL and its~~ associated IROL T_V~~.~~ for any IROL;

~~1.1.3.~~5.2.4. The associated Contingency(ies~~).~~); and

~~1.1.4.~~5.2.5. The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. ~~The~~Each impacted Transmission Operator ~~shall provide any SOLs it developed~~within its Reliability Coordinator Area, the value of the stability limits established pursuant to ~~its Reliability Coordinator~~Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission ~~Service Providers that share its portion of the~~ Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

~~1.2.~~5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

~~**R1.1.** The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.~~

~~**R1.2.** The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

~~**R2.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

~~**R2.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~

~~**R2.2.** If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Each requesting Transmission Operator within its Reliability Coordinator~~.~~

~~A. Measures~~

5.5. ~~The~~ Area, requested SOL information for its Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each be able~~ Area, on a mutually agreed upon schedule.

~~**M4.**~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that ~~it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.** The~~ the Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.**~~**M5.** ~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and~~ provided the ~~list and the limits to its Reliability Coordinators~~information in accordance with Requirement ~~6~~R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

~~**2.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organization~~

~~**2.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~**2.3. Data Retention**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**2.4. Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**2.4.1** SOL Methodology(ies)~~

~~**2.4.2** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**2.4.3** Evidence that SOLs were distributed~~

~~**2.4.4** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**2.4.5** Distribution schedules provided by entities that requested SOLs~~

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs~~The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for ~~the~~its Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Reliability Coordinator's~~ its System Operating Limit Methodology ("SOL Methodology~~. (R1)~~") as established in FAC-011-4.
R2.	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	The Transmission Operator ~~has established~~did not establish SOLs for its portion of the Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the~~its Reliability Coordinator's SOL Methodology.~~ (R2)~~
R3.	~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than,~~	~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50%~~	~~There are~~The Transmission Operator provided its SOLs	~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are~~

	~~25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~for the Planning~~to its Reliability Coordinator ~~Area~~, but ~~50% or more, but less than 75% of these~~did not provide its SOLs ~~are inconsistent with~~at the periodicity at which the ~~Planning Coordinator's SOL Methodology. (R3)~~RC needs such information to perform its reliability functions.	~~inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
R4.	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission ~~Planner has established SOLs for~~Operator in its ~~portion of the Planning~~Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Planning Coordinator's~~its SOL Methodology. ~~(R4)~~
R5 .	~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting~~	~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45~~

	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~ The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~ The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~ The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6 .	~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~ N/A	~~Not applicable.~~ N/A	~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ N/A	~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ The Reliability Coordinator with an established IROL, or the

				Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional ~~Differences~~Variances

None ~~identified.~~

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

6.2 The associated stability criteria used as part of determining the instability;

6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;

6.4 Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission

Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	The Planning Coordinator used less limiting stability	The Planning Coordinator used less limiting stability	The Planning Coordinator failed to implement a

		performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in the Reliability Coordinator's SOL Methodology.
R4.	N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.
R5.	N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

R6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which

System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

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Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s)

- Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

[*New/Modified/Retired*] Terms in the NERC Glossary of Terms

Proposed New Definition(s):
System Voltage Limit: The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- Transmission Planner
- Transmission Operator

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and term, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and term are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, and FAC-014-2 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2015-09 Establish and Communicate System Operating Limits** project. The electronic form must be submitted by **8 p.m. Eastern, Monday, November 13, 2017**.

Documents and information about this project are available on the project page. If you have questions, contact either Senior Standards Developer, Darrel Richardson at (609) 613-1848 or Al McMeekin at (404) 446-9675.

Preface

The Reliability Standards that address System Operating Limits (SOLs) – FAC-010, FAC-011, and FAC-014 have remained essentially unchanged since their initial versions. Since that time, many improvements have been made to the body of Reliability Standards, specifically those in the TPL, TOP, and IRO families of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. One of the primary objectives of Project 2015-09 is to make changes to the FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards and the revised definitions of Operational Planning Analysis (OPA) and Real-time Assessments (RTA).

Please provide your responses to the questions listed below along with any detailed comments.

FAC-010-3 System Operating Limits Methodology for the Planning Horizon

Background Information

In 2015, the FAC Standard Periodic Review Team (PRT) completed a review of the FAC-010-3, FAC-011-3, and FAC-014-2 Reliability Standards. The review focused on reconciling these three standards with new and revised TPL, TOP and IRO standards that did not exist at the time that the three FAC standards were drafted and approved. Regarding FAC-010-3, the PRT concluded that the requirements in FAC-010-3, which specify the development of an SOL methodology for the planning horizon, are not necessary inputs to the Bulk-Electric System (BES) planning process.

In May of 2015, the PRT posted a preliminary recommendation to retire FAC-010-3. Industry comments on this recommendation indicated a general agreement with the PRT position.

NERC Project 2015-09 was initiated later in 2015 to address all PRT recommendations through the formation of a standard drafting team (SDT). The SDT further concluded that the requirements in FAC-010-3 are redundant with TPL-001-4 and no longer provide a necessary reliability function. Furthermore, the SOL Methodology for the planning horizon does not serve a purpose within the operations horizon. Therefore, the SDT proposes the retirement of FAC-010-3 in its entirety.

In addition to the proposed retirement of FAC-010-3, the SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations. This proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required to the currently effective FAC-010-3 due to its overall redundancy with TPL-001-4.

Questions

1. The SDT is recommending retirement of FAC-010-3 and has provided justification in the “FAC-010/FAC-015 Rationale” and “FAC-010-3 Mapping Document.” Do you agree that the proposed retirement of FAC-010-3 does not create a reliability gap? Please provide supporting rationale.

   ☐ Yes
   ☐ No

   Comments:

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

Background Information

The SDT contends that the requirements in FAC-011-4 improve clarity, reduce redundancy, and create better alignment and continuity with the currently-effective TOP and IRO standards. One of the primary changes in FAC-011-4 is seen in the focus on the establishment of Facility Ratings (FAC-011-4 Requirement R2), System Voltage Limits (FAC-011-4 Requirement R3), and stability limits (FAC-011-4 Requirement R4). The other requirements in FAC-011-4 do not represent a significant departure from the currently-effective FAC-011-3. The SDT's intent is that the Facility Ratings, the System Voltage Limits, the stability limits, and the IROLs that are used in operations are those that are established in accordance with the proposed FAC-011-4, and are those that are monitored and assessed through OPAs and RTAs to ultimately determine whether the System is performing reliably.

Currently effective FAC-011-3 Requirement R2 requires that the "Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following…" Sub requirements R2.1 and R2.2 proceed to describe the BES performance that is required for the pre-Contingency state (R2.1) and for the post-Contingency state for single Contingencies (R2.2). The mapping document for Requirement R2 and its sub requirements describes the SDT's assertion that "BES performance" as stated in FAC-011-3, Requirement R2, R2.1 and R2.2 is not determined through SOLs in and of themselves, rather, that "BES performance" is determined through OPAs and RTAs, where SOLs are an input to the OPAs and RTAs. This is a similar construct to the TPL-001-4 wherein Facility Ratings, voltage criteria, and stability criteria are inputs to the Planning Assessment.

Stability limits that are used in OPAs and RTAs are established by developing stability performance criteria and then running studies to determine stability limits that result in System performance within the criteria. These stability limits can be established prior to OPAs and RTAs, or they can be established as part of OPAs and RTAs. The timing of the establishment of stability limits is not as important as the accuracy and applicability of the stability limits. On the other hand, Facility Ratings and System Voltage Limits are direct inputs into the OPAs and RTAs and do not require a "study" such as an OPA or an RTA to establish them. For example, "BES performance" for Facility Ratings is determined through OPAs and RTAs which assess the flow on Facilities in the pre- and post-Contingency states. When unacceptable "BES performance" is identified in an OPA, Transmission Operators (TOPs) and Reliability Coordinators (RCs) are required by the Reliability Standard to develop an Operating Plan to address that unacceptable "BES performance". Similarly, when unacceptable "BES Performance" is identified in the RTA, TOPs and RCs are required to implement an Operating Plan to address the unacceptable "BES performance." In accordance with the NERC SOL Whitepaper (and the proposed definition of SOL Exceedance), unacceptable "BES performance" for either the pre-Contingency state or the post-Contingency state translates to SOL exceedance, which serves to prompt the development (for OPAs) or implementation (for RTAs) of Operating Plans. This is a similar construct to the TPL-001-4 whereby unacceptable system performance prompts the development and implementation of a Corrective Action Plan in the Planning Assessment.

The definitions of OPA and RTA include the analyses of the pre- and post-Contingency states, and include language that addresses the expected conditions (OPA) and actual conditions (RTA) such as Facility outages, load, and generation dispatch. OPAs and RTAs are the assessments for System performance and require the development of Operating Plans (for OPAs) and implementation of Operating Plans (for RTAs) to address any potential (for OPAs) or actual (for RTAs) SOL exceedances identified in the OPA or RTA. As such, the drafting team did not carry forward into FAC-011-4the concepts of FAC-011-3, Requirement R2, R2.1 and R2.2 pertaining to BES performance. The following part of R2.1 “In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.” has been retained in FAC-011-4, Requirement R4 Part 4.4 for stability limits which may be “determined” or “calculated” prior to the OPA and RTA. The FAC-011-3 mapping document provides a more detailed justification for not carrying Requirement R2, R2.1 and R2.2 forward in its current form.

FAC-011-3, Requirement R2, R2.3 describes an acceptable System response to single Contingencies. Requirement R2, R2.4 contains the statement, “To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.” Again, these sub requirements of Requirement R2 address the establishment of SOLs that “provide a certain level of BES performance”. Requirement R2, R2.3 and R2.4 were originally written to be congruous with concepts in the TPL standards that existed at that time. Today, these concepts are found in Table 1 of TPL-001-4. The TPL standards have been improved over the last several years, so the language in FAC-011-3 Requirement R2 does not correlate one-to-one with the various items in Table 1 of TPL-001-4:

<table>
<tr><th>FAC-011-3 Requirements</th><th>Corresponding Items in TPL-001-4 Table 1</th></tr>
<tr><td>R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.</td><td rowspan="4">1. Items “b, c, and e” under the Steady State & Stability section:
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.</td></tr>
<tr><td>R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or
(b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies</td></tr>
<tr><td>R2.3.3. System reconfiguration through manual or automatic control or protection actions.</td></tr>
<tr><td>R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.</td></tr>
</table>

	2. The far right column in Table 1 addresses the allowance of Non-Consequential Load Loss for various Contingency events. For P1 events, Non-Consequential Load Loss is not allowed; however, there is a footnote 12 caveat noted. (See below) 3. For P3 and P6 events (two consecutive single Contingencies with system adjustments between the first -1 event and the second -1 event), Non-Consequential Load Loss is allowed; however, there is a footnote 9 caveat noted (See below)

Footnote 9 – An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Footnote 12 – An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4, Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the System) are required to be reflected in the establishment of stability limits.

However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is supposed to be operated", the operational decisions related to customer interruption and System reconfiguration are governed by the Operating Plan. The SDT contends that TOPs need to have the flexibility in their Operating Plan(s) to address the wide-ranging operational issues they may encounter, including the interruption of other network customers if the RTA identifies unacceptable System performance. This may be necessary to return the System to an acceptable state of pre and post-Contingency System performance for subsequent RTAs (i.e., N-1 secure state) after a Contingency event occurs. In the SDT's opinion, FAC-011-3, Requirement R2, R2.3.1 would be better addressed by a reliability guideline regarding Consequential Load Loss; however, the SDT notes that recent clarifications to the definition of Bulk Electric System (BES) excluded the Facilities described in Requirement R2, R2.3.1. As such it would be counter-intuitive and confusing to reference such Facilities in a NERC reliability guideline. FAC-011-3, Requirement R2, R2.3.2 (b) has become obsolete since the 30-minute RTA requirements in the IRO and TOP standards have become effective. Since the RTA is conducted at least once every 30 minutes and requires implementation of an Operating Plan for unacceptable system performance, the Real-time conditions will not be "more adverse than anticipated in the corresponding studies". Accordingly, the SDT sees no need for retaining these requirements which may restrict how TOPs are allowed to operate the System (e.g. interruption of customers/load). Such guidance is better suited for a reliability guideline on Operating Plans rather than a NERC Reliability Standard.

Questions

2. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.1 and R2.2, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

   ☐ Yes
   ☐ No

   Comments:

3. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.3 and R2.4, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

   ☐ Yes
   ☐ No

   Comments:

4. Are there any reliability objectives of FAC-011-3, Requirement R2, R2.3 and R2.4 that you maintain need to be preserved in requirements relating to the development of Operating Plans which would reside outside the FAC family of standards? Please explain your response.

   ☐ Yes
   ☐ No

   Comments:

5. In the Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, the Federal Energy Regulatory Commission (FERC) classified underfrequency load-shedding schemes (UFLS) as a “safety net” and stated that UFLS should not be a tool used by Bulk Electric System operators in the derivation of stability limits. In Order 763, FERC asserted that UFLS “provide last resort system preservation measures.” The SDT agrees with the FERC, and has footnoted Requirement R4, Part 4.6 of proposed FAC-011-4 to state:

   “The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits.”

   With regard to undervoltage load-shedding schemes (UVLS), FERC states in Order 818 (Order) that they are “[not] persuaded by [the] argument that UVLS programs should be considered in operations planning and real-time operations. We understand that [the argument] refers to the consideration of UVLS programs in the derivation of Interconnection Reliability Operating Limits (IROLs) for Category B contingencies as defined in the currently-effective transmission planning standard TPL-002-0b (commonly known as N-1 contingencies under normal system operation).” With this understanding, we disagree […] on the relevance of using UVLS in the derivation of IROLs for N-1 contingencies. The 2003 Canada-United States Blackout Report stated that “[s]afety nets should not be relied upon to establish transfer limits.” This statement is consistent with the performance criteria established in TPL-002-0b and TPL-001-4, which generally prohibit the loss of non-consequential load for certain N-1 Contingencies. We conclude that UVLS programs under PRC-010-1 are examples of such “safety nets” and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies.”

   While the Order clearly addresses the prohibition of using UVLS for calculating SOLs for single (N-1) Contingencies, the Order does not address the use of UVLS for calculating SOLs for Contingencies more severe than single (N-1) Contingencies, for example for N-1-1 operations scenarios or for N-2 Contingencies such as breaker failure Contingencies or common tower Contingencies that may be deemed credible for operations. For this reason, the proposed FAC-011-4, Requirement R4, Part 4.6

does not specifically address the use of UVLS, but allows the RC to describe its allowed use as an "other automatic post-Contingency mitigation action" within its SOL Methodology.

Do you agree that the SDT should allow the use of UVLS in the establishment of stability limits? If not, please explain and provide alternative language.

☐ Yes
☐ No

Comments:

6. If you have any other comments **that you haven't already provided** in response to questions 2-5, please provide them here.

Comments:

FAC-014-3 Establish and Communicate System Operating Limits

Background Information

FAC-014-2 provides the requirements for the establishment and communication of SOLs by operating and planning entities. The requirements in this standard prescribe the responsibilities for establishing SOLs and list the defined set of entities which receive the established SOLs and other related information. This standard works with FAC-010-3 and FAC-011-3 in a coordinated effort to establish and distribute SOL information.

Given the SDT proposal to retire FAC-010-3 and to adopt FAC-015-1 (whitepaper), there is no longer a need for planning entities (Planning Authorities and Transmission Planners) to establish and distribute SOLs. As a result, the SDT proposes revising the function of FAC-014 in revision three to provide the requirements necessary for operating entities to establish SOLs and to disburse their SOLs, and other related information, to a defined set of entities. With removing the need for planning entities to have an SOL methodology and to establish and communicate SOLs, Requirements R2, R3 and R4 from FAC-014-2 are removed in the SDT's proposed FAC-014-3. Also, Requirement R6, and subparts 6.1 and 6.2, are augmented and included in the SDT's proposed FAC-015-1, Requirement R6. The remaining operations related requirements in FAC-014-2 were kept or altered for improvement in the SDT's proposed FAC-014-3 revision. Questions related to the removal of Requirements R2, R3, and R4 from FAC-014-2 are not included in this comment form. Rather, they are included in the comment forms related to the retirement of FAC-010-3 and the addition of FAC-015-1. Accordingly, please refrain from addressing the removal of these requirements when providing comments for FAC-014-3.

Questions

7. The SDT is proposing to divide existing Requirement R1 of FAC-014-2 into three requirements in FAC-014-3 to clearly indicate which entities have the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) [the RC], System Operating Limits (SOLs) [the TOP] and stability limits that impact more than one TOP in its Reliability Coordinator Area [the RC] into proposed Requirements R1, R2, and R4, respectively. Do you agree with the proposed changes? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

8. Existing FAC-014-2, Requirement R5, R5.2 requires the Transmission Operator (TOP) to provide its SOLs to its Reliability Coordinator (RC) and Transmission Service Providers (TSPs) that share its portion of the RC Area. The SDT is proposing in Requirement R3 of FAC-014-3 to exclude the TSPs from that communication chain. Other requirements in existing standards (MOD-028-2, Requirement R7, MOD-029-2a, Requirement R4, and MOD-030-3, Requirement R2.6) require the TOP to provide the Total Transfer Capabilities (TTCs), Total Flowgate Capabilities (TFCs), along with supporting information and assumptions to TSPs. Because the TTCs and TFCs already reflect the impact(s) of any SOLs, the SDT deemed retention of the existing language unnecessary. Do you agree with the proposed change? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

9. The SDT relocated the reliability objectives of existing Requirement R6 of FAC-014-2 into Requirement R6 of proposed Reliability Standard FAC-015-1 such that all Planning Coordinator and Transmission Planner responsibilities will be housed within one standard. Do you agree with the proposed change? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

10. If you have any other comments **that you haven't already provided** in response to questions 7-9, please provide them here.

   Comments:

FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

Background

The drafting team contends that the proposed requirements in FAC-015-1 improve coordination of limits and criteria between the planning and operating standards. The primary focus of FAC-015-1 is to coordinate limits and criteria utilized in Planning Assessments with those identified within or established in accordance with the Reliability Coordinator's SOL Methodology. FAC-015 coordinates Facility Ratings, System steady-state voltage limits, and stability performance criteria (i.e. limits and criteria) utilized in Planning Assessments with the Facility Ratings, System Voltage Limits, and stability performance criteria utilized in the operations horizon. The requirements are drafted to provide for a construct where the limits and criteria utilized in Planning Assessments are at least as limiting if not more limiting that those used in operations. Failing to have limit and criteria consistency between planning and operations might result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e., planning the System less conservatively than the System is operated) This will minimize the potential for unnecessary corrective actions up to and including load shed that could result from planning the system with limits and criteria less conservative.

The SDT has specifically identified the Planning Assessment of the Near-Term Transmission Planning Horizon as the assessment that carries the requirements as these are the closest assessments before transitioning into the operations horizon. The SDT also arranged the standard such that Requirements R1 – R3 focus on Facility Ratings, System steady-state voltage limits, and stability performance criteria individually. The SDT added the statement "the Planning Coordinator shall provide a technical justification to its Reliability Coordinator" to allow for flexibility in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized (e.g. up-rating a line in a future project). This ensures that the RC will also be aware of these rare circumstances.

Requirement R4 requires provision of the coordinated limits and criteria by the PCs to its TPs. Requirement R5 requires the TP to use limits and criteria that are equally limiting or more limiting than the coordinated Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC.

Requirement R6 requires the PC to communicate any instability, Cascading, or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted RC and TOP. IRO-017-1, Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2, Part 2.4 and Requirement R4 in TPL-001-4 which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1, Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Planning Horizon are provided to impacted RCs and TOPs. The information itemized in Requirement R6 is a key consideration for RCs and TOPs in the establishment of stability SOLs and IROLs.

Requirement R6 lists items that a PC is required to provide each impacted RC and TOP. This requirement serves as an enhancement of FAC-014-2, Requirement R6, and the information is intended to be used by impacted RCs and TOPs for their consideration in subsequent development of stability limits, IROLs and associated Operating Plans. Requirement R6, Part 6.4 requires the PC to communicate "any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation." This item was included because planners are allowed to invoke these items in accordance with TPL-001-4 to meet the prescribed performance requirements. The drafting team contends it is critical that impacted RCs and TOPs are made aware when the items listed in Requirement R6, Part 6.4 have been invoked to address or avoid instability, Cascading or uncontrolled separation. Otherwise, impacted RCs and TOPs may not have any idea that such risks are present and that they are addressed through the use of the measures listed in Part 6.4. This unawareness can compromise the RC's and TOP's abilities to ensure that stability limits, IROLs, and associated Operating Plans are developed as necessary to address the risks identified by the PCs.

Questions

11. FAC-015-1 is predicated on the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative/restrictive/limiting than those found in (or established in accordance with) the RC's SOL Methodology, allowing for justified exceptions. Do you agree with this principle? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

12. Do you agree that coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria as required in Requirements R1-R3 should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

   ☐ Yes
   ☐ No

   Comments:

13. In Requirements R1 – R3, the SDT is proposing to allow a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology. Do you agree that this provides adequate flexibility (in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized; e.g., up-rating a line in a future project) without compromising reliability? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

☐ Yes
☐ No

Comments:

14. Do you agree that the information identified in Requirement R6 is necessary for each impacted RC and TOP to properly evaluate instability, Cascading, or uncontrolled separation identified in planning assessments for use in establishing stability limits and IROLs in the operations horizon? If not, please explain and provide alternative language.

☐ Yes
☐ No

Comments:

15. Do you agree that the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

☐ Yes
☐ No

Comments:

16. If you have any other comments **that you haven't already provided** in response to questions 11-15, please provide them here.

Comments:

Definition: System Voltage Limit

Background Information

The SDT proposes to add the term "System Voltage Limit" to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT modified the previously proposed definition based on feedback from the previous informal comment period: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT acknowledges that TPL-001-4 Requirement R5 requires criteria for "post-Contingency voltage deviations". The current proposed changes to FAC-011-4 and the proposed definition of System Voltage Limits does not specifically include "post-Contingency voltage deviations", however the SDT determined the proposed changes to the FAC standards do not prevent an entity from monitoring and operating within "post-Contingency voltage deviations" that may be more limiting than the System Voltage Limits.

According to the definition, it is acceptable for a RC's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. The SDT asserts that the definition as worded allows for the term to be applied in both the operations and planning time horizons.

Questions

17. Do you agree with the proposed definition of System Voltage Limit? If not, please explain and provide alternative language.

☐ Yes
☐ No

Comments:

Implementation Plan

Question

18. Do you agree with the Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.

☐ Yes
☐ No

Comments:

Cost Effectiveness

Question

19. The SDT asserts the combination of proposed FAC-011-4, FAC-014-3, and FAC-015-1 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

☐ Yes
☐ No

Comments:

Mapping Document for FAC-010-3

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 provides the Planning Coordinator (PC) with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirements R4 and R5 address the communication and use of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in Planning Assessments between PCs and Transmission Planners (TPs).

FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R6 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events)

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)
1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)
1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)
1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.
1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:
1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:
- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-015-1 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

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	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

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		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL Methodology. In the proposed construct, PC and TP identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via FAC-015-1, Requirement R6. IROLs are established by the RC as required by FAC-014-3. TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).
R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning

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performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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	Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

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R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1:** **Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1:** **Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1:** **Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

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	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

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	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard."
R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

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Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

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		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. <u>FAC-011-4 Requirement R2</u>: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. <u>Operational Planning Analysis</u> is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R6 and Part 6.1. R6. Each Reliability Coordinator shall include in its SOL Methodology 6.1. A description of how to identify the subset of SOLs that qualify as IROLs.	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	These requirements are addressed in: 1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs. 2. The definition of OPA and RTA 3. FAC-011-4, Requirement R4 addresses the establishment of stability limits and the associated performance requirements. 4. FAC-011-4 Requirement R6 and its Parts relating to IROLs.	"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and

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R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	5. The definition of IROL and the TOP and IRO standards that address operation within IROLs. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL	implementation of an Operating Plan to address that SOL exceedance. The items in approved FAC-011-3, Requirement R2 and its sub-requirements are addressed through the related TOP standards that reference SOL exceedance. 1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances. 2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA. 3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once every 30 minutes to identify SOL exceedances. 4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances. 5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.

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	exceedance identified as part of its Real-time monitoring or Real-time Assessment. IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time	6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA. 7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances. 8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA. The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability

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	Assessment is performed at least once every 30 minutes. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status*	limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state. Regarding the stability portions of Requirement R2, R2.1 and R2.2: FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.

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	or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"*	Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements. Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology. Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area. Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the

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	FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.	RC to establish IROLs in accordance with its SOL Methodology. IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.

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	4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions. IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.*	

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	FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology: 6.1. A description of how to identify the subset of SOLs that qualify as IROLs. 6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v. FAC-014-3, Requirement R1: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). IRO-009-2, Requirement R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an	

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	IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4.

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FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping.	Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP

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transmission system, and the transmission system topology.	4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other	standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary

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	automatic post-Contingency mitigation actions. The issues that are more centric to “how the system is to be operated” are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide	manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to “how the system is to be operated”, the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

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	its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-012-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather

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	impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	than a NERC Reliability Standard requirement.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined

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R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of

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		the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement R6 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1.

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multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits. FAC-015-1 Requirement R6: R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	In FAC-015-1, Requirement R6, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R6, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1]. Footnote 1 states "The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits."	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by including other automatic mitigation actions that are not a RAS, for example UVLS.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the

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	Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability	FAC-011-4, Requirement R6, Part 6.2 R6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R6, Part 6.2.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operating Limit (IROL) and criteria for developing any associated IROL T_V.	criteria for developing any associated IROL T_V.	
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R8, Parts 8.1 and 8.4: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology; 8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R8, Parts 8.1 and 8.4 Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it. Non-adjacent RCs, which are addressed in Part 8.4, do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Part 8.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it.

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FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.2 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.3 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R8, Part 8.3.

Mapping Document for FAC-014-2

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
<u>FAC-014-2, Requirement R1</u> R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	<u>Requirements R1, R2, and R4 of FAC-014-3</u> R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

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Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	1. FAC-011-4, Requirement R8, Part 8.2 2. FAC-015-1, Requirements R 1 – R6 FAC-011-4, Requirement R8, Part 8.2: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement R8, Part 8.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes made to FAC-011-4 and FAC-014-3 represent an improvement for

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Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-015-1: R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its	planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings used in Planning Assessments, Requirement R2 addresses the System steady state voltage limits used in Planning Assessments, and Requirement R3 addresses the stability performance criteria used in Planning Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning.

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	Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more	Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. By implementing Requirements R1 – R5 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-

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	limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-	state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.

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	Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-014-2, Requirement R5, R5.1 R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) FAC-014-3, Requirement R5: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs,

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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the	which addresses RC-to-RC communication and coordinated operations issues.

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	information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages.	

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	1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
<u>FAC-014-2, Requirement R5, R5.2</u> R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 <u>FAC-014-3, Requirement R3</u> R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. <u>MOD-028-2, Requirement R7:</u> R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

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	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. <u>MOD-029-2a, Requirement R4:</u> R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. <u>MOD-030-3, Requirement R2.6:</u> [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
<u>FAC-014-2, Requirement R5, R5.3 and R5.4</u> R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-015-1, Requirements R1 – R6 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 <u>FAC-015-1, Requirements R1 –R6:</u>	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. Implementing the processes required in FAC-015-1, Requirements R1 – R3

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and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the	provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. FAC-015-1, Requirements R1 – R5 result in PC and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their

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	Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-	Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The

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	state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;	TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. <u>MOD-028-2, Requirement R7:</u> R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. <u>MOD-029-2a, Requirement R4:</u> R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

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	MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement R8: R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. 8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any),	FAC-015-1, Requirement R6 R6. Each Planning Coordinator shall communicate any instability, Cascading or	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows:

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from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	• FAC-015-1, Requirement R6 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement R6 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement R6 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement R6 because all instances of instability identified by the PC are to be communicated

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		to the RC in accordance with FAC-015-1, Requirement R6. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement R6 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Part 8.4.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**

This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology

This document provides the standard drafting team’s (SDT’s) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator’s System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.

VSL Justifications for FAC-015-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R5	
Proposed VRF	**Medium**

This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

VSL Justifications for FAC-015-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R6	
Proposed VRF	Medium

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Rationales for FAC-010-3 (Retirement) and FAC-015-1

September 2017

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning Authority must have a documented methodology for establishing SOLs (including IROLs) used in the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires Planning Coordinators (PCs) and Transmission Planners (TPs) to establish and communicate SOLs and IROLs used in the planning horizon consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, namely, those in the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically, the retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4, all of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3, and all of the IRO standards have been modified. The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address in some manner the foundational reliability concept of reliable system performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC standards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC standards by minimizing redundancy, allowing for better continuity from the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable system performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a methodology for establishing SOLs for use in the planning horizon, as well as the corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs were unnecessary and not useful for ensuring reliable planning or reliable operations. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. The SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

Under the current construct, PCs and RCs may have significantly different SOL Methodologies as the currently-effective Reliability Standards (FAC-010-3, FAC-011-3 & FAC-014-2) do not have any link requiring coordination between the methodologies. Furthermore, the nature of the current construct does not address continuity between planning and operations and may potentially result in a system not adequately planned for operational needs. The SDT's proposed changes help address the potential for inconsistencies between the PC's SOL Methodology and the RC's SOL Methodology.

Additionally, because of the evolution of the TPL standards, there are many redundancies in the responsibilities for PCs and Transmission Planners (TPs) between those in FAC-010/FAC-014 and those in TPL-001-4. In fact, planners are under no obligation to use (and many do not use) the PC's SOL Methodology for their Planning Assessments. Under Reliability Standard TPL-001-4, the SOLs established for the planning horizon pursuant to the FAC-010 and FAC-014 Reliability Standards are not necessary for reliable planning.

The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct. Under the proposed construct, the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new standard FAC-015-1 to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System (steady-state) voltage limits, and stability performance criteria used in their planning assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria as determined in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 and proposed FAC-015-1such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

- Clarity and efficiency of communication of limits and criteria between planning and operating entities is improved with FAC-015-1.

System Operating Limits in the Planning Horizon

There are two different time frames in which the system is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology developed pursuant to FAC-010-3 is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the system could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the system (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission system. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that if operated within, will result in the system being *operated* reliably. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their system. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the system is being reliably *operated*. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the system during operations.

One of the key aspects of the proposed new construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term

"Operating" in System "Operating" Limits. The components of SOLs include the use of Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use Facility Ratings provided by Facility Owners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement R6 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those systems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those systems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different system conditions (different transfers, weather assumptions, load levels) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3 and R5.4 require its use. Retirement of FAC-010-3 would consequently necessitate retirement of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

The requirements in the TPL-001-4 standard require a comprehensive Planning Assessment and includes the establishment of limits and criteria (Facility ratings, System steady-state voltage limits, and stability performance criteria) and the *methodology* used by the planners (TPL-001-4, Requirement R6) to identify System instability (Cascading, voltage instability, or uncontrolled islanding) for the planning horizon. TPL-001-4 requires that a summary of the results of the assessment (TPL-001-4, Requirement R2) and a list of critical Contingencies that are expected to produce the most severe System impacts (TPL-001-4, Requirement R4.5) be included in the Planning Assessment. Further, TPL-001-4, Requirement R8 requires that the Planning Assessment, which includes all of information listed above, be distributed to any functional entity that has a reliability related need, for which the RC qualifies.

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is an established methodology* used in the reliable planning of the BES. This comprehensive methodology describes how the transmission system should be studied, addresses the establishment of performance criteria, prescribes the outages that must be analyzed, identifies the outages that do not meet the performance requirements, and requires determination of the corrective actions that should be taken to ensure future system reliability. This established methodology meets and exceeds performance requirements identified in FAC-010-3 SOL methodology. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

<u>Modeling</u>:

TPL-001-4, Requirement R1 – "Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment."

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement R5 – "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."

TPL-001-4, Requirement R6 – "Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – "Steady State & Stability Performance Planning Events"

<u>Reporting</u>:

TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement R8 – "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

Corrective Action:

TPL-001-4, R2.7: "For the planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met."

Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as “Requirements Recommended for Retirement” in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC’s P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that the planners use limits and criteria in their Planning Assessments that are as limiting, if not more limiting, than the limits and criteria developed in accordance with the RC’s SOL Methodology.

The Perceived “Gap”

The perceived *gap* stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the SOL Methodology in the operations horizon with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate “methodology” around limits and criteria is also removed.

Development of FAC-015-1

Despite the comprehensive requirements in TPL-001-4 and to address the perceived gap, the SDT developed FAC-015-1 with the title “Coordination of Planning Assessments with the RC’s SOL Methodology” and the purpose “to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the RC’s SOL Methodology.” FAC-015-1 will require the PC to implement processes that ensure that the Facility Ratings, voltage limits, and stability performance criteria used in its planning assessment are equal or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC’s SOL Methodology.

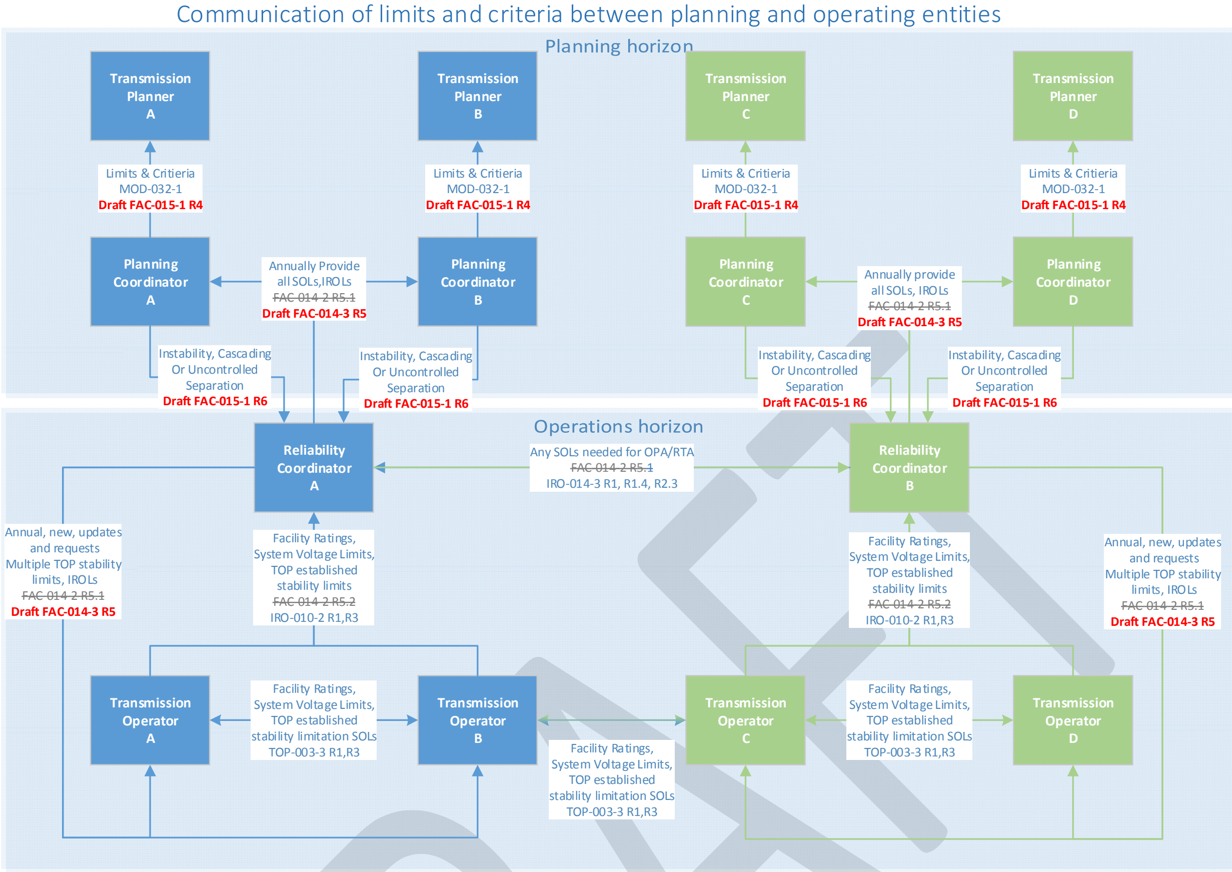
Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC’s and TP’s responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

The SDT is improving clarity and efficiency of communications by establishing a single point of contact between the RC and the PC for communication of SOLs from the operations horizon to the planning horizon. The PC, which is more familiar with and interacts regularly with TPs, is the entity responsible for communicating the SOLs to impacted Transmission Planners. This removes communications directly from the RC to the TPs and keeps the PC in the direct path of all SOLs from the operations time horizon. The requirements for FAC-015-1 can be thus met during times of annual preparation for its annual Planning Assessments.

The figure below shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.

Communication of limits and criteria between planning and operating entities



FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2. With FAC-010-3 and FAC-014-2 Requirements R3, R4, R5.3 and R5.4 being effectively replaced by proposed FAC-015-1, the communication of stability related information identified in FAC-014-2 Requirement R6 from the PC to the RC remained. The SDT has opted to relocate the content addressed in FAC-014-2 Requirement R6 into newly proposed FAC-015-1 Requirement R6 rather than keep in FAC-014. This relocation allowed for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Rationales for FAC-010-3 (Retirement) and FAC-015-1

September 2017

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning Authority must have a documented methodology for establishing SOLs (including IROLs) used in the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires Planning Coordinators (PCs) and Transmission Planners (TPs) to establish and communicate SOLs and IROLs used in the planning horizon consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, namely, those in the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically, the retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4, all of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3, and all of the IRO standards have been modified. The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address in some manner the foundational reliability concept of reliable system performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC standards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC standards by minimizing redundancy, allowing for better continuity from the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable system performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a methodology for establishing SOLs for use in the planning horizon, as well as the corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs were unnecessary and not useful for ensuring reliable planning or reliable operations. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. The SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

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The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct. Under the proposed construct, the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new standard FAC-015-1 to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System (steady-state) voltage limits, and stability performance criteria used in their planning assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria as determined in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 and proposed FAC-015-1such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

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There are two different time frames in which the system is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology developed pursuant to FAC-010-3 is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the system could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the system (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission system. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that if operated within, will result in the system being *operated* reliably. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their system. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the system is being reliably *operated*. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the system during operations.

One of the key aspects of the proposed new construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term

"Operating" in System "Operating" Limits. The components of SOLs include the use of Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use Facility Ratings provided by Facility Owners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement R6 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those systems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those systems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different system conditions (different transfers, weather assumptions, load levels) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3 and R5.4 require its use. Retirement of FAC-010-3 would consequently necessitate retirement of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

The requirements in the TPL-001-4 standard require a comprehensive Planning Assessment and includes the establishment of limits and criteria (Facility ratings, System steady-state voltage limits, and stability performance criteria) and the *methodology* used by the planners (TPL-001-4, Requirement R6) to identify System instability (Cascading, voltage instability, or uncontrolled islanding) for the planning horizon. TPL-001-4 requires that a summary of the results of the assessment (TPL-001-4, Requirement R2) and a list of critical Contingencies that are expected to produce the most severe System impacts (TPL-001-4, Requirement R4.5) be included in the Planning Assessment. Further, TPL-001-4, Requirement R8 requires that the Planning Assessment, which includes all of information listed above, be distributed to any functional entity that has a reliability related need, for which the RC qualifies.

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is an established methodology* used in the reliable planning of the BES. This comprehensive methodology describes how the transmission system should be studied, addresses the establishment of performance criteria, prescribes the outages that must be analyzed, identifies the outages that do not meet the performance requirements, and requires determination of the corrective actions that should be taken to ensure future system reliability. This established methodology meets and exceeds performance requirements identified in FAC-010-3 SOL methodology. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

<u>Modeling</u>:

TPL-001-4, Requirement R1 – “Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment.”

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement R5 – “Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.”

TPL-001-4, Requirement R6 – “Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.”

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – “Steady State & Stability Performance Planning Events”

<u>Reporting</u>:

TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement R8 – "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

Corrective Action:

TPL-001-4, R2.7: "For the planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met."

Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as "Requirements Recommended for Retirement" in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC's P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that the planners use limits and criteria in their Planning Assessments that are as limiting, if not more limiting, than the limits and criteria developed in accordance with the RC's SOL Methodology.

The Perceived "Gap"

The perceived *gap* stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the SOL Methodology in the operations horizon with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate "methodology" around limits and criteria is also removed.

Development of FAC-015-1

Despite the comprehensive requirements in TPL-001-4 and to address the perceived gap, the SDT developed FAC-015-1 with the title “Coordination of Planning Assessments with the RC’s SOL Methodology” and the purpose “to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the RC’s SOL Methodology.” FAC-015-1 will require the PC to implement processes that ensure that the Facility Ratings, voltage limits, and stability performance criteria used in its planning assessment are equal or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC’s SOL Methodology.

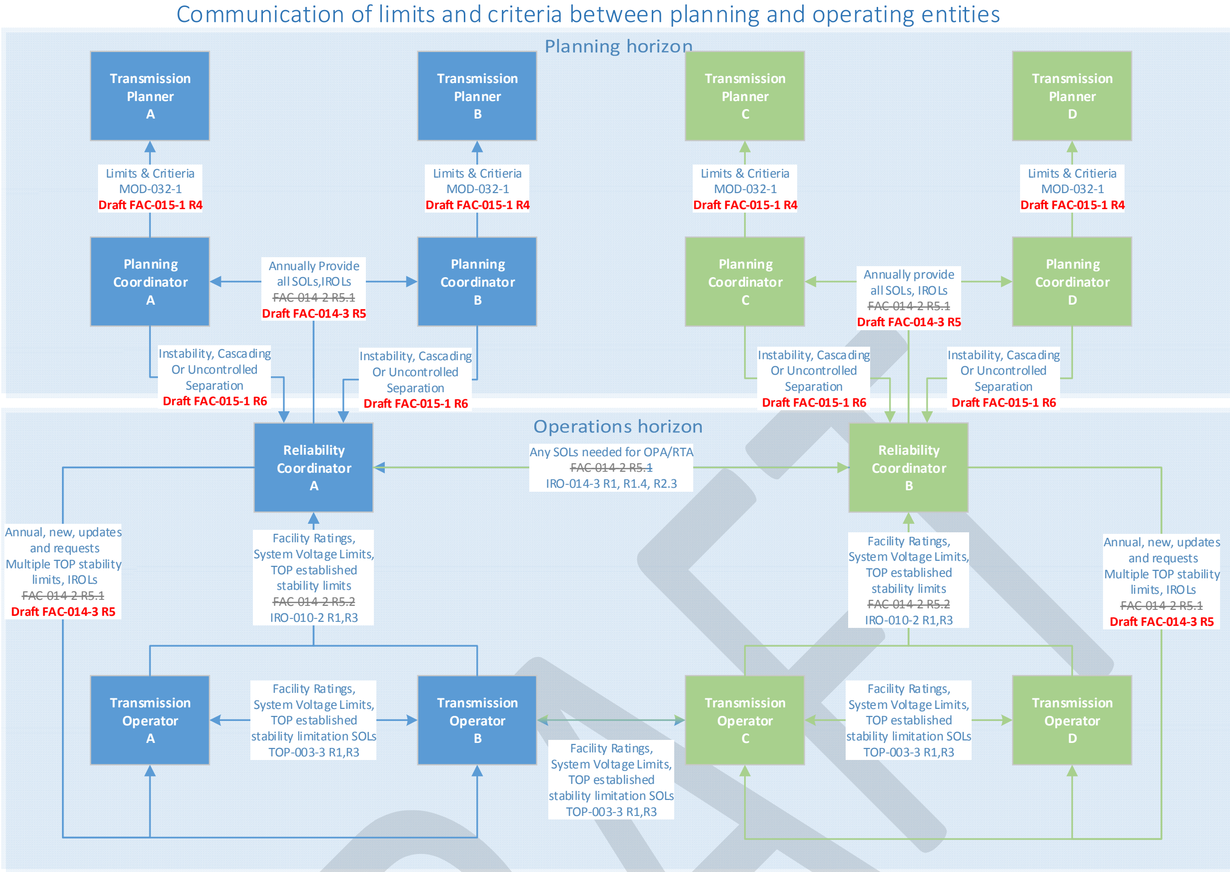
Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC’s and TP’s responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

The SDT is improving clarity and efficiency of communications by establishing a single point of contact between the RC and the PC for communication of SOLs from the operations horizon to the planning horizon. The PC, which is more familiar with and interacts regularly with TPs, is the entity responsible for communicating the SOLs to impacted Transmission Planners. This removes communications directly from the RC to the TPs and keeps the PC in the direct path of all SOLs from the operations time horizon. The requirements for FAC-015-1 can be thus met during times of annual preparation for its annual Planning Assessments.

The figure below shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.

Communication of limits and criteria between planning and operating entities



FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2. With FAC-010-3 and FAC-014-2 Requirements R3, R4, R5.3 and R5.4 being effectively replaced by proposed FAC-015-1, the communication of stability related information identified in FAC-014-2 Requirement R6 from the PC to the RC remained. The SDT has opted to relocate the content addressed in FAC-014-2 Requirement R6 into newly proposed FAC-015-1 Requirement R6 rather than keep in FAC-014. This relocation allowed for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Rationale for FAC-011-4

September 2017

Requirement R1

Each Reliability Coordinator shall have a methodology for establishing SOL (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires that the SOL Methodology shall be applicable for developing SOLs used in the operations horizon. The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires that the SOL Methodology state that SOLs shall not exceed associated Facility Ratings. Facility Ratings to be used in operations as System Operating Limits (SOLs) are addressed through FAC-011-4 Requirement R2 and therefore is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires that the SOL Methodology include a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs). This language is preserved in Requirement R6.

Requirement R2

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure that the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still responsible for determining the Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between the TOP and RC during operations.

Requirement R3

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1 Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;

3.2 Require that System Voltage Limits respect the Facility voltage Ratings;

3.3 Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;

3.4 Identify the lowest allowable System Voltage Limit;

3.5 Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6 Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;

3.7 Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its Reliability Coordinator Area for facility-based voltage limits, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identifies the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any Facility voltage Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any Facility voltage Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that UVLS should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are set above all UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1 Specify stability performance criteria, including any margins applied. The criteria shall include the following:

4.1.1 steady-state voltage stability;

4.1.2 transient voltage response;

4.1.3 angular stability;

4.1.4 System damping;

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5;

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area;

4.4 Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1].

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of system damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, this requirement may be met by providing language in the SOL Methodology describing which TOP (or identifying that the RC) has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out

[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10%, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the Reliability Coordinator Area (including other Reliability Coordinator Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require entire Reliability Coordinator Area modeling to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are “valid” (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include “An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations”, the stability limits used in OPA/RTA should be “valid” for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) are designed “to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.” In the establishment of stability limits under Requirement R4 Part 4.6, UFLS programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS as a “last resort system preservation measure”.

Requirement R5

Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1 The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device;
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2 Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4 The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in checking for all types of SOL exceedances in OPAs and RTAs (thermal, voltage and stability limits). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that at a minimum must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events such as inadvertent breaker operation and bus faults may be considered if the probability of such an event is relevant. The method for determining those Contingencies must also be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.4 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R6 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

Each Reliability Coordinator shall include in its SOL Methodology:

6.1 A description of how to identify the subset of SOLs that qualify as IROLs.

6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

Rationale R6

The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.

Requirement R7

Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Rationale R7

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R7 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own Transmission Operator Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R8

Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

8.1 Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;

8.2 Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.3 Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4 Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

Rationale R8

Requirement R8 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses "responsible for planning" instead of "models any portion of" to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology.

Rationales for FAC-014-3

September 2017

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC who has wide-area responsibility will identify such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to identify stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area).

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area,, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and,

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOP)s. This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause of when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements in pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for SOLs to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Both Requirement R5 Parts 5.4 and 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Rationale R6

Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:

> *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*

Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.

The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.

Rationale for FAC-015-1

September 2017

Requirement R1

Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the Reliability Coordinator's (RC's) System Operating Limit (SOL) Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a Planning Coordinator (PC) area be coordinated between the PC and applicable Transmission Planners (TPs). It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC to use Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. If less limiting Facility Ratings are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R2

Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R2

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.
The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level

and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, the PC is required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R3

Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RCs SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the Reliability Coordinator's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When the PC performs the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R4

Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Requirement R5

Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Rationale R4 and R5

Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate

These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.

Requirement R6

Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its

Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

6.2 The associated stability criteria used as part of determining the instability;

6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;

6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R6

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and Transmission Operators (TOPs).

The information itemized in Requirement R6 is a key consideration for RC and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R6 will supplement the severe System conditions identified Requirements R4 Parts 4.4 & 4.5 of TPL-001-4.

Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

STD	Standard Reference	Comment / Proposed Action
BAL standards		No Action Required
CIP standards		
CIP-002-5.1a	Attachment 1: 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. After retirement of FAC-10-3, PCs and TPs will no longer be required to establish IROLs using FAC-010-3; however, IROLs will continue to be required to be established by the RC. Similar to Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a, FAC-014-3, Requirement R6, requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the Generator Owners (GO) and Transmission Owners (TOs). FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a

		list of Facilities owned by that entity that are critical to the derivation of the IROL." While Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modify Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise Requirement R2, Part 2.6 of Attachment 1 in response to the retirement of FAC-010-3 to eliminate PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's

		Planning Assessment for the Near-Term Transmission Planning Horizon.
CIP-014-2	Applicability 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the PC and TP (and RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. Similar to 4.1.1.3 of the Applicability section of CIP-014-2, FAC-014-3, Requirement R6 requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the GOs and TOs. FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.” While 4.1.1.3 of the Applicability section of CIP-014-2 could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modifying 4.1.1.3 of the Applicability section of CIP-014-2 to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in

		the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise 4.1.1.3 of the Applicability section of CIP-014-2 in response to the retirement of FAC-010-3 to eliminate the PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
COM standards		No Action Required
EOP standards		No Action Required
FAC standards		
FAC-003-4	**Introduction:** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	The Applicability section of the Introduction specifies "applicable lines" and includes overhead transmission lines (< 200 kV) identified as an element of an IROL by the PC. Requirements R1 and R2 reference "applicable lines" and IROLs as well. "Applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. All overhead transmission lines that operate at 200 kV and above are included as "applicable

	Requirements **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below… **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	lines” (4.2.1). Qualifications are then being made to include < 200 kV transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management. The retirement of FAC-010 does not create a reliability gap here. The language in Parts 4.2.2 and 4.3.1.2 of FAC-003-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-014; however, IROLs are required to be established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.” FAC-003-4 is applicable to GOs and TOs. Accordingly, these entities are made aware of IROLs and the facilities critical to the derivation of those IROLs from the RC as per FAC-014-3 Requirement R6 above. While Parts 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired

		prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 in response to the retirement of FAC-010-3 to eliminate references to the PC determining IROLs. A future team should determine the appropriateness for the elements identified as applicable to 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
FAC-013-2	**Requirements** **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs).	R 1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The retirement of FAC-010-3 does not create a reliability gap here as SOLs will continue to be established by TOPs and communicated to PCs through FAC-014-3 Requirement R5. The PC can then use the SOL information to satisfy Requirement R1, R1.2. Requirement R1.2 does not specify whether the SOLs are sourced from the RC or by the PC. **Recommendations:** Consideration should also be given to clarify FAC-013-2 Requirement R1.2 to eliminate the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment.

		Possible solutions include changing the language of Requirement R1, R1.2 to reference the performance requirements per Table 1 of TPL-001-4, or revising the language to replace SOL with "Facility Ratings, System steady-state voltage limits, and the Transmission Planners' stability criteria." A future team should consider eliminating the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment as described above.
FAC-014-2	Requirements R3 – R5	Under Revision
INT standards		No Action Required
IRO standards		No Action Required
MOD standards		No Action Required
NUC standards		No Action Required
PER standards		No Action Required
PRC standards		
PRC-002-2	**Requirements:** **R5.** Each Responsible Entity shall: **5.1.** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.2.** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).	Direct language around SOL and IROL does not specify PC SOL methodology and therefore does not preclude the RC's methodology from determining the applicable limits. However, the time horizon for the requirement is "long-term planning." Additionally, the SOLs referred to are stability based only. The retirement of FAC-010-3 does not create a reliability gap here. IROLs and stability-related SOLs are communicated to the GOs

	5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).	and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." The Applicability section of PRC-002-2 describes the Responsibly Entities: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator Regardless of the designation of the Responsible Entity in a given Interconnection, either is able to provide the GOs and TOs the information in Requirement R5, Parts 5.1.2 and 5.1.4. The information is ultimately sourced from the RC, but FAC-014-3, Requirement R5, Parts 5.1, 5.2, and subparts requires the RC to communicate the relevant information to the PC, who, in turn, can communicate the information to the applicable GO and TO as required by PRC-002-2, Requirement R5, Parts 5.1.2 and 5.1.4. FAC-014-3 R5. Each Reliability Coordinator shall provide:

		5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). While subparts 5.1.2 and 5.1.4 of PRC-002-2 would benefit from a revision in response to the retirement of FAC-010, the need for such a revision does not rise to the level of creating a reliability gap if FAC-010 is retired prior to the time these requirements can be changed. **Recommendations:** It is recommended that this standard be modified at some point in the future to update the designation of the Responsible Entities defined in the Standard. In the absence of this change, however, the currently defined Responsible Entities are capable of providing the necessary information through the mechanisms described above.
PRC-023-4	**Attachment B** - Criteria Section:	Direct reference to FAC-010 made in this attachment.

	If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.	Attachment B sets the applicability of facilities operated below 200 kV (similar to FAC-003). These items reference PRC-023-4, Requirement R6, to which Attachment B is applicable. The language in part B2 of Attachment B of PRC-023-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-010-3; however, IROLs are established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." Accordingly, the GO and the TO are able to use the IROL information provided by the Reliability Coordinator. While part B2 of Attachment B for PRC-023-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise Attachment B of PRC-023-4 in response to the retirement of FAC-010-3 to eliminate the references to FAC-10, PC's determining IROLs and IROLs in the Planning Horizon for identification of circuits as a monitored Facility of an Interconnection Reliability Operating Limit (IROL).

		A future team should consider the appropriateness for the circuits identified as applicable to Attachment B of PRC-023-4 to include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
PRC-026-1	R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	Direct reference is made to the PC's SOL Methodology. Footnote 1 on page 3 of 84 references FAC-014-2, R3. Similar to the reference identified in Requirement R5, Part 5.1.2 of PRC-002-2, Requirement R1 of PRC-026-1 references the identification of facilities that are sensitive to angular stability constraints. Stability-related SOLs are communicated to the Planning Coordinator through FAC-014-3, Requirement R5, Parts 5.1 and, 5.2: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL;

		5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). With this information, the PC can communicate the necessary SOL information to the applicable GO and TO as required by PRC-026-1, Requirement R1. While Criteria 1 and 2 of PRC-026-1 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these criteria given the above requirement for the RC. **Recommendations:** Revise PRC-026-1, Requirement R1 in response to the retirement of FAC-010-3 to eliminate the term, “Planning Coordinator’s Methodology” which references FAC-10 and remove the reference to SOLs identified by the PC. A future team should consider that the PRC-026 R1 criteria reference Elements associated with angular stability as identified in the PC or TP’s Planning Assessment for the Near-Term Transmission Planning Horizon.
TOP standards		No Action Required
TPL standards		No Action Required
VAR standards		No Action Required

Reliability Standard Audit Worksheet[1]

FAC-011-4 - System Operating Limits Methodology for the Operations Horizon

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1						X						
R2						X						
R3						X						
R4						X						
R5						X						
R6						X						
R7						X						
R8						X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Text entry area with white background:	Auditor-supplied information

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i] :

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has a Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R2
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's Methodology for establishing SOLs (i.e., SOL Methodology) includes the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
	Verify the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations addresses the use of common Facility Ratings between the Reliability

	Coordinator and the Transmission Operators in its Reliability Coordinator Area.
Note to Auditor:	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1. Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Address the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R3
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL Methodology includes the method for Transmission Operators to determine the System Voltage Limits to be used in operations.
	Verify the method for Transmission Operators to determine the System Voltage Limits to be used in operations:
	(3.1) Requires that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology
	(3.2) Requires that System Voltage Limits respect the Facility voltage Ratings;
	(3.3) Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings
	(3.4) Identifies the lowest allowable System Voltage Limit;
	(3.5) Addresses the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;
	(3.6) Addresses coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and
	(3.7) Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.
Note to Auditor:	

Auditor Notes:

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R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s)**	**Description of Applicability of Document**

				or Section(s)	

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R4

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL Methodology includes the method for determining the stability limits to be used in operations.
	Verify the method for determining the stability limits to be used in operations:
	(4.1) Specifies stability performance criteria, including any margins applied, and includes:
	(4.1.1) steady-state voltage stability;
	(4.1.2) transient voltage response;
	(4.1.3) angular stability; and
	(4.1.4) System damping.
	(4.2) Requires that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.
	(4.3) Describes how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.
	(4.4) Describes how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;
	(4.5) Describes the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.
	(4.6) Describes the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement R6 to identify the Contingencies for use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL Methodology includes the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs).
	Verify the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) includes:
	(5.1) The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:
	(5.1.1) Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; or • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
	(5.2) Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.
	(5.3) Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.
	(5.4) The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement R6 to identify the Contingencies for use in determining stability limits.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator shall include in its SOL Methodology:

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

6.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R1
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL Methodology includes:
	(6.1) A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).
	(6.2) Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any

	associated IROL T_V.
Note to Auditor:	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R7
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL Methodology includes the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s).
	Verify the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s) addresses the periodicity of SOL communication.
Note to Auditor:	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each Reliability Coordinator shall provide its SOL Methodology and any changes to the SOL Methodology prior to the effective date of the SOL Methodology, to:

8.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates it has a reliability-related need;

8.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

8.3. Each Transmission Operator within its Reliability Coordinator Area.

M8. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

Registered Entity Response (Required):
Question: Has the entity made any changes to its SOL Methodology during the audit period? ☐ Yes ☐ No
If Yes, provide a list of changes including the date the change became effective. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Question: Has the entity received a request for its SOL Methodology from a Reliability Coordinator that indicated it has a reliability-related need for the SOL Methodology? ☐ Yes ☐ No
If Yes, provide a list of requests received. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL Methodology) within the entity's Reliability Coordinator Area.
Evidence the SOL Methodology and any changes to the SOL Methodology were provided to each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates it has a reliability-related need.
Evidence the SOL Methodology and any changes to the SOL Methodology were provided to each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area.

Evidence the SOL Methodology and any changes to the SOL Methodology were provided to each Transmission Operator within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R8

This section to be completed by the Compliance Enforcement Authority

	(8.1) Verify that, prior to the effective date of the SOL Methodology, the entity provided its SOL Methodology to each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates it has a reliability-related need.
	(8.1) For all, or a sample of, changes made to the entity's SOL Methodology, verify entity provided its SOL Methodology to each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates it has a reliability-related need, prior to the effective date of the updated SOL Methodology.
	(8.2) Verify that, prior to the effective date of the SOL Methodology, the entity provided its SOL Methodology to each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area
	(8.2) For all, or a sample of, changes made to the entity's SOL Methodology, verify entity provided its SOL Methodology to each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area, prior to the effective date of the updated SOL Methodology.
	(8.3) Verify that, prior to the effective date of the SOL Methodology, the entity provided its SOL Methodology to each Transmission Operator within its Reliability Coordinator Area.
	(8.3) For all, or a sample of, changes made to the entity's SOL Methodology, verify entity provided its SOL Methodology to each Transmission Operator within its Reliability Coordinator Area., prior to the effective date of the updated SOL Methodology.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.

The full text of FAC-011-4-N may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	XX/XX/XXXX	RSAW Working Group	New Document

Revision History for RSAW Template

Version	Date	Reviewers	Revision Description
0.9	11/6/2013	RSAW Working Group	Initial Draft
1.0	11/20/2013	CMFG	First Review
1.1	12/1/2014	RSAW TF, CMFG	Minor text changes
1.2	2/17/2014	Jerry Hedrick	Removed Internal Controls approach for additional consideration
1.3	4/9/2014	CIP-014-1 RSAW DT; RSAW TF	Changed the footnote on Evidence Requested to an Endnote. Moved example language from multiple areas to Developer's Guide.
3.0	1/20/2017		Deleted IA, LSE, PSE columns from Applicability; changed PA column to PA/PC. Updated page footer with new template version.

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

FAC-014-3 – Establish and Communicate System Operating Limits

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1						X						
R2										X		
R3										X		
R4						X						
R5						X						
R6						X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology).

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i] **:**

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's System Operating Limit Methodology (SOL Methodology).
Evidence IROLs for the entity's Reliability Coordinator Area have been established in accordance with entity's SOL Methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R1
This section to be completed by the Compliance Enforcement Authority

	Verify the entity has established IROLs for its Reliability Coordinator Area in accordance with its SOL Methodology.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's Reliability Coordinator's System Operating Limit Methodology (SOL Methodology).
Evidence the entity established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R2
This section to be completed by the Compliance Enforcement Authority

	Verify the entity has established SOLs in accordance with its Reliability Coordinator's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL Methodology.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's Reliability Coordinator's System Operating Limit Methodology (SOL Methodology).
Evidence SOLs were provided to the entity's Reliability Coordinator in accordance with the Reliability Coordinator's SOL Methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the entity provided its SOLs to its Reliability Coordinator in accordance with the Reliability Coordinator's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's System Operating Limit Methodology (SOL Methodology).
Evidence entity established stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with entity's SOL Methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R4

This section to be completed by the Compliance Enforcement Authority

	Verify the entity established stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with entity's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 - 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the information in accordance with Requirement R5.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity provided SOLs for Reliability Coordinator Area (including the subset of SOLs that are IROLs) to each Planning Coordinator within its Reliability Coordinator Area at least once every twelve calendar months.
Evidence the entity provided the information specified in Parts 5.2.1 – 5.2.5 for each established stability limit and each established IROL to each impacted Planning Coordinator within its Reliability Coordinator Area at least once every twelve calendar months.
Evidence the entity provided the value of the stability limits established pursuant to Requirement R4 and each

IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, to each impacted Transmission Operator within its Reliability Coordinator Area.
Evidence the entity provided the information identified in Requirement R5 Parts 5.2.2 - 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, to each impacted Transmission Operator within its Reliability Coordinator Area.
Evidence the entity provided requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule, to each requesting Transmission Operator within its Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R5

This section to be completed by the Compliance Enforcement Authority

	(5.1) Verify the entity provided SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) to each Planning Coordinator within its Reliability Coordinator Area at least once every twelve calendar months.
	(5.2) Verify the entity provided the following information for each established stability limit and each established IROL to each impacted Planning Coordinator within its Reliability Coordinator Area at least once every twelve calendar months:
	(5.2.1) The value of the stability limit or IROL
	(5.2.2) Identification of the Facilities that are critical to the derivation of the stability limit or IROL;
	(5.2.3) The associated IROL T_v for any IROL;
	(5.2.4) The associated Contingency(ies); and
	(5.2.5) The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).
	(5.3) Verify the entity provided the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-

	time Assessments, to each impacted Transmission Operator within its Reliability Coordinator Area.
	(5.4) Verify the entity provided the information identified in Requirement R5 Parts 5.2.2 - 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, to each impacted Transmission Operator within its Reliability Coordinator Area.
	(5.5) Verify the entity provided each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

Registered Entity Response (Required):
Question: Is the entity impacted by IROL(s)? ☐ Yes ☐ No
If Yes, provide a list of IROL(s) for which the entity is impacted. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
A list of Facilities that are critical to the derivation of each IROL, including identification of the Transmission Owner or Generator Owner that owns each Facility.
Evidence the entity provided Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R6

This section to be completed by the Compliance Enforcement Authority

	For all, or sample of, Facilities that are critical to the derivation of an IROL, verify the entity provided Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.
The full text of STD-0XX-N may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]
Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]
The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	10/10/2017	NERC Compliance Assurance, RSAW Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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Reliability Standard Audit Worksheet[1]

FAC-015-1 – Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: [On-site Audit | Off-site Audit | Spot Check]
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1					X							
R2					X							
R3					X							
R4					X							
R5											X	
R6					X							

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
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The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

Registered Entity Response (Required):
Question: Does the entity use less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology? ☐ Yes ☐ No
If Yes, provide evidence the entity provided a technical justification to its Reliability Coordinator. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity, when developing its steady-state modeling data requirements, implemented a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology.
Reliability Coordinator's SOL Methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the entity, when developing its steady-state modeling data requirements, implemented a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology.
	Verify the entity provided a technical justification to its Reliability Coordinator if the entity uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

Registered Entity Response (Required):
Question: Does the entity use less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology?☐ Yes ☐ No
If Yes, provide evidence the entity provided a technical justification to its Reliability Coordinator. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity implemented a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
Reliability Coordinator's SOL Methodology

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R2

This section to be completed by the Compliance Enforcement Authority

	Verify the entity implemented a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
	Verify the entity provided a technical justification to its Reliability Coordinator if the entity uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

Registered Entity Response (Required):
Question: Does the entity use less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology? ☐ Yes ☐ No
If Yes, provide evidence the entity provided a technical justification to its Reliability Coordinator. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity implemented a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology.
Reliability Coordinator's SOL Methodology

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the entity implemented a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology.
	Verify the entity provided a technical justification to its Reliability Coordinator if the entity uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Has the entity received a request from a Planning Coordinator for Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment? ☐ Yes ☐ No
If Yes, provide a list of requests received. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity provided Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R4

This section to be completed by the Compliance Enforcement Authority

	Verify the entity provided Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity used Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R5
This section to be completed by the Compliance Enforcement Authority

	Verify the entity used Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Note to Auditor:

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

6.1. The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

6.2. The associated stability criteria used as part of determining the instability;

6.3. The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;

6.4. Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

6.5. Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

Registered Entity Response (Required):
Question: Has the entity identified instability, Cascading or uncontrolled separation in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment?
☐ Yes ☐ No
If Yes, provide a list of instances of instability, Cascading or uncontrolled separation identified in either the Planning Assessment of the Near-Term Transmission Planning Horizon or the Transfer Capability assessment. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity communicated any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator.
Evidence communication to each impacted Reliability Coordinator and Transmission Operator included each item specified in Parts 6.1 – 6.5.

The entity's most recent Planning Assessment of the Near-Term Transmission Planning Horizon.
The entity's most recent Transfer Capability assessment.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-015-1, R6

This section to be completed by the Compliance Enforcement Authority

	For each instance of instability, Cascading or uncontrolled separation identified in either the entity's Planning Assessment of the Near-Term Transmission Planning Horizon or the entity's Transfer Capability assessment, verify the entity communicated the instability, Cascading or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.
	For all, or a sample of, communication from the entity to impacted Reliability Coordinators and Transmission Operators, verify the communication included:
	(6.1) The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
	(6.2) The associated stability criteria used as part of determining the instability;
	(6.3) The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
	(6.4) Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and
	(6.5) Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.
Note to Auditor: Planning Coordinators are required to prepare a Planning Assessment of the Near-Term Transmission Planning Horizon in TPL-001-4 R2, and conduct a Transfer Capability assessment in FAC-013 R2.	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.
The full text of STD-0XX-N may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]
Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: “Based on NERC’s…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: “We affirm NERC’s…….

Selected Glossary Terms [If developer deems applicable]
The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	10/10/2017	NERC Compliance Assurance, RSAW Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Standards Announcement

Project 2015-09
Establish and Communicate System Operating Limits
FAC-011-4, FAC-014-3 and FAC-015-1

Draft Reliability Standard Audit Worksheets (RSAWs) Posted for Industry Comment through November 13, 2017

Now Available

Draft RSAWs are posted on the project page for industry comment through **8 p.m. Eastern**, **Monday, November 13, 2017** for the following standards:

- **FAC-011-4 - System Operating Limits Methodology for the Operations Horizon**
- **FAC-014-3 – Establish and Communicate System Operating Limit**
- **FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology**

Submit feedback regarding the draft RSAWs to RSAWfeedback@nerc.net.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson at (609) 613-1848 or Al McMeekin at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-09
Establish and Communicate System Operating Limits

Formal Comment Period Open through November 13, 2017
Ballot Pools Forming through October 30, 2017

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, November 13, 2017** for:

1. **FAC-010-3** – System Operating Limits Methodology for the Planning Horizon (retirement)
2. **FAC-011-4** – System Operating Limits Methodology for the Operations Horizon
3. **FAC-014-3** – Establish and Communicate System Operating Limit
4. **FAC-015-1** – Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
5. **Implementation Plan**
6. **Proposed definition of System Voltage Limit**

Commenting

Use the Standards Balloting & Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, October 30, 2017.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standards, implementation plan, proposed definition and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 3-13, 2017**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
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404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-09 Establish and Communicate System Operating Limits | FAC-011-4, FAC-014-3, FAC-015-1, Implementation Plan, System Voltage Limit
Comment Period Start Date:	9/29/2017
Comment Period End Date:	11/14/2017
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-011-4 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-015-1 IN 1 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan IN 1 OT 2015-09 Establish and Communicate System Operating Limits System Voltage Limit | New Definition IN 1 DEF

There were 56 sets of responses, including comments from approximately 166 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT is recommending retirement of FAC-010-3 and has provided justification in the "FAC-010/FAC-015 Rationale" and "FAC-010-3 Mapping Document." Do you agree that the proposed retirement of FAC-010-3 does not create a reliability gap? Please provide supporting rationale.

2. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.1 and R2.2, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

3. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.3 and R2.4, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

4. Are there any reliability objectives of FAC-011-3, Requirement R2, R2.3 and R2.4 that you maintain need to be preserved in requirements relating to the development of Operating Plans which would reside outside the FAC family of standards? Please explain your response.

5. Do you agree that the SDT should allow the use of UVLS in the establishment of stability limits? If not, please explain and provide alternative language.

6. If you have any other comments that you haven't already provided in response to questions 2-5, please provide them here.

7. The SDT is proposing to divide existing Requirement R1 of FAC-014-2 into three requirements in FAC-014-3 to clearly indicate which entities have the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) [the RC], System Operating Limits (SOLs) [the TOP] and stability limits that impact more than one TOP in its Reliability Coordinator Area [the RC] into proposed Requirements R1, R2, and R4, respectively. Do you agree with the proposed changes? If not, please explain.

8. Existing FAC-014-2, Requirement R5, R5.2 requires the Transmission Operator (TOP) to provide its SOLs to its Reliability Coordinator (RC) and Transmission Service Providers (TSPs) that share its portion of the RC Area. The SDT is proposing in Requirement R3 of FAC-014-3 to exclude the TSPs from that communication chain. Other requirements in existing standards (MOD-028-2, Requirement R7, MOD-029-2a, Requirement R4, and MOD-030-3, Requirement R2.6) require the TOP to provide the Total Transfer Capabilities (TTCs), Total Flowgate Capabilities (TFCs), along with supporting information and assumptions to TSPs. Because the TTCs and TFCs already reflect the impact(s) of any SOLs, the SDT deemed retention of the existing language unnecessary. Do you agree with the proposed change? If not, please explain.

9. The SDT relocated the reliability objectives of existing Requirement R6 of FAC-014-2 into Requirement R6 of proposed Reliability Standard FAC-015-1 such that all Planning Coordinator and Transmission Planner responsibilities will be housed within one standard. Do you agree with the proposed change? If not, please explain.

10. If you have any other comments that you haven't already provided in response to questions 7-9, please provide them here.

11. FAC-015-1 is predicated on the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative/restrictive/limiting than those found in (or established in accordance with) the RC's SOL Methodology, allowing for justified exceptions. Do you agree with this principle? If not, please explain.

12. Do you agree that coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria as required in Requirements R1-R3 should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

13. In Requirements R1 – R3, the SDT is proposing to allow a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology. Do you agree that this provides adequate flexibility (in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized; e.g., up-rating a line in a future project) without compromising reliability? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

14. Do you agree that the information identified in Requirement R6 is necessary for each impacted RC and TOP to properly evaluate instability, Cascading, or uncontrolled separation identified in planning assessments for use in establishing stability limits and IROLs in the operations horizon? If not, please explain and provide alternative language.

15. Do you agree that the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

16. If you have any other comments that you haven't already provided in response to questions 11-15, please provide them here.

17. Do you agree with the proposed definition of System Voltage Limit? If not, please explain and provide alternative language.

18. Do you agree with the Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.

19. The SDT asserts the combination of proposed FAC-011-4, FAC-014-3, and FAC-015-1 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Lucia Beal	Southern Maryland Electric Cooperative	3	RF
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Midwest Reliability Organization	Cynthia Kneisl	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO

					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC

					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Janis Weddle	6		Chelan PUD	Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
Associated Electric Cooperative, Inc.	Mark Riley	1		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A	3	SERC

						Electric Power Cooperative		
					William Price	M and A Electric Power Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion NextERA Con-Ed	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					j.Scott Williams	City Utilities of Springfield, MO	1,4	SPP RE
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
					Robert Gray	Board of Public Utilities (BPU), Kansas, City	NA - Not Applicable	SPP RE
					Steve McGie	Board of Public Utilities (BPU), Kansas, City	NA - Not Applicable	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE

1. The SDT is recommending retirement of FAC-010-3 and has provided justification in the "FAC-010/FAC-015 Rationale" and "FAC-010-3 Mapping Document." Do you agree that the proposed retirement of FAC-010-3 does not create a reliability gap? Please provide supporting rationale.

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
FAC-010-3 contains regional differences (e.g. common corridor 500 kV outages, no cascading for loss of two PV units) that the California ISO plans the WECC system to that provide for a more resilient system. With the exception of this Question and Question 15, the California ISO supports the comments of the ISO/RTO Council Standards Review Committee. However, the California ISO has provided numerous additional comments in the sections below related to the new proposed FAC-015-1 standard.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCE agrees with the drafting team that the new TPL-001-4 ensures the reliable planning of the transmission system and addresses each of the reliability components of FAC-010-3. The mapping document adequately and exhaustively demonstrates where the components of FAC-010 are addressed in other standards or are no longer relevant under the new SOL/IROL construct.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

BPA agrees with the SDT's rationale.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes, I agree that it is unnecessary to have a planning SOL methodology. The TPL requirements along with changes to FAC-011, FAC-014 and the new requirements discussed in the FAC-015 (which I think should be covered in the TPL standard, but my comments on that are covered in the FAC-015 section) adequately define what ratings/limits should be used to plan the system. **Note:** While we agree with the retirement of FAC-010, we will be voting "No" because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation supports retiring FAC-010-3 because the requirements are adequately addressed in other NERC Standards.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Comment	
FAC-010 has always had minimal reliability value as it was restating what was already occurring as part of the TPL standards. Manitoba Hydro agrees the FAC-010-3 is completely redundant with TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Yes, I agree that it is unnecessary to have a planning SOL methodology. The TPL requirements along with changes to FAC-011, FAC-014 and the new requirements discussed in the FAC-015 (which I think should be covered in the TPL standard, but my comments on that are covered in the FAC-015 section) adequately define what ratings/limits should be used to plan the system. **Note:** While we agree with the retirement of FAC-010, we will be voting "No" because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the retirement of FAC-010-3 as part of this project. However SRP will be voting Negative on the ballot due to recommended changes with the other proposed standards.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	

Answer	Yes
Document Name	

Comment

Peak agrees that the retirement of FAC-010 does not create a reliability gap. The SDT did a thorough job in their assessment of FAC-010 in the mapping document. As is pointed out in the supporting documentation, there is an abundance of redundancies between FAC-010 (and the associated requirements in FAC-014) and TPL-001-4. Peak supports the retirement of FAC-010 and the addition of FAC-015 as described in the supporting documentation.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	Yes
Document Name	

Comment

Requirements in FAC-010-3 are covered by TPL_001_4

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	Yes
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Entergy agrees with the mapping document, the reliability impact is covered elsewhere.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
The coordination between the Planning and Operations horizons can and should occur without the added confusion of having a separate set of planning SOLs/IROLs.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	

Answer	Yes
Document Name	
Comment	
CHPD confirms that it views the reliability function of FAC-010-3 to be duplicative of those objectives also contained in the TPL-001-4 and to some extent, FAC-013. CHPD believes the retirement of FAC-010-3 will not create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
System Operating Limits in the planning horizon in the Eastern Interconnection are generally the applicable steady-state ratings of the facilities, which are included in the powerflow models and are tested in a wide range of contingency analyses as required by standard TPL-001-4. Voltage limits are generally published in transmission planning criteria documents.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We strongly support the retirement of FAC-010-3 and the SDT rationale.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	

Answer	Yes
Document Name	
Comment	
ATC agrees with the retirement of FAC-010-3 due to the proposed revisions to FAC-011 and FAC-014 as well as the creation of a proposed FAC-015-1 standard. These proposals adequately address the necessary coordination between operations and planning.	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	2015-09_Unofficial_Comment_Form_092717_ERCOT_final.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	
Document Name	
Comment	

MEAG Power supports all Southern Company responses herein. Scott Miller

Likes 0	
Dislikes 0	

Response

2. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.1 and R2.2, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

Interpretation of Facility Ratings, System Voltage Limits and Stability limits are confusing and can be easily misinterpreted.   In the background information above, SDT states that 'For example, "BES performance" for Facility Ratings is determined through OPAs and RTAs which assess the flow on Facilities in the pre- and post-Contingency states…'   As it can be seen Facility Ratings can be interpreted as Thermal ratings only. Facility Ratings should include both Thermal ratings and voltage ratings of the equipment.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

Commentary and Support: In the existing FAC-011-3 paradigm, System Operating Limits (SOLs) are essentially the means used to limit the system so that the Bulk Electric System (BES) has acceptable performance both pre-contingency and post-contingency. Although not a term used in FAC-011-3, the concept of 'Reliable Operation' from the NERC Glossary of Terms is helpful in describing the objective:

Reliable Operation: "Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits…"

In the new, proposed FAC-011-4 paradigm, the focus is removed from SOLs as the tool to ensure secure system operations, and instead moves to assessing whether expected operating conditions are within acceptable performance pre- and post-contingency. If studies indicate otherwise, entities and the RC implement and utilize Operating Plans to keep the system within acceptable performance.

Conceptually, FAC-011-3 and FAC-011-4 are very similar. One uses SOLs to keep the system within acceptable performance; the other uses Operating Plans when unacceptable performance is identified. Therefore, the reliability objectives are maintained, although the terminology and approach has now changed.

In the description of the proposed FAC-011-4, SOLs now play a role similar to Facility Ratings, Voltage Criteria, and Stability Criteria; SOLs are now part of the criteria to assess acceptable BES performance via OPAs and RTAs.

Comment 1: CHPD would like to see an approach where the assessment of the system is started with Facility Ratings and performance criteria, and SOLs, if required, be used as an operational tool to support operating within those Facility Ratings and performance criteria, along with generation re-dispatch, topology re-configuration, etc.

Comment 2: Regarding the contingencies transferred from FAC-011-3 to FAC-011-4 to align with the TPL contingencies, there are two discontinuities worth mentioning.

In the old FAC-011-3, R2.2.2. listed “Loss of any generator, line, transformer, or shunt device without a Fault”.

The new FAC-011-4 description is now “…or without a Fault: generator; transmission circuit; transformer; shunt device; or single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.”

In TPL-001-4, the analogous no-fault contingency is a category P2.1, and is described in TPL-001-4 Table 1 as “Opening of a line section w/o a fault”.

In summary, the new FAC-011-4 adds the single pole block to the list of no-fault outages. This probably has minor impact, but CHPD is unsure why it is being added. The second change, which is maintained, is of greater mention – there has been a discontinuity between the TPL requirements for no-fault (line section w/o a fault) and both the old and new FAC-011 standards (generator, line (old) / transmission circuit (new) transformer, shunt device (or single pole block). This could mean that these non-fault events aren’t planned for through TPL, but are expected to be operated to through the FAC standard. CHPD requests this be examined by the Standard Drafting Team to see if a better alignment between TPL and FAC can be arranged. Additionally, the difference between the old FAC-011-3 ‘line’ and the new FAC-011-4 ‘transmission circuit’ could be clarified if these are intended to be the same thing, or if differences are intended (and if so, what are those differences).

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1

Answer	No
Document Name	

Comment

With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No

Document Name	
Comment	

We do not agree with the proposed definition of SOL Exceedance. In our proposed definition below, we excluded the criteria for which contingencies should be assessed. We do not believe that the state of the system (pre or post contingency) should be included in the definition of SOL Exceedance, but should be left outside that definition. We believe that an RC's SOL methodology should define the conditions in which an SOL should not be exceeded.

Southern's Proposed definition:

SOL Exceedance - An operating condition, as determined in Real -time Monitoring, wher

An exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. Predicted exceedances, such as those identified through OPAs and RTAs, may or may not occur as they are just that, predicted. Predicted exceedances should not be defined and subject to the stringent set of limitations and requirements that SOL Exceedances should be. Furthermore, how predicted exceedances are identified, assessed, operationally planned for and mitigated should be the responsibility of the Reliability Coordinator. Therefore, any such definition for predicted exceedances should remain in the respective RC's SOL methodology.

Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	

The existing TOP standards adequately cover BES performance.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

The language in Requirement 2: “for Transmission Operators to determine the applicable owner -provided Facility Ratings used in operations.” needs work. Suggested language: “for Transmission Operators to determine SOLs based upon the Transmission Owner-provided Facility Ratings.”

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	Yes
Document Name	

Comment

We support the ISO RTO Council Comments.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees that no reliability gap is introduced with the removal of the requirements R2, R2.1, and R2.2. Peak agrees with the justifications set forth in the FAC-011 mapping document for these requirements. Peak also believes that the removal of requirements R2, R2.1 and R2.2 would be strengthened by adoption of the proposed definition of SOL Exceedance.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that these requirements should be removed from FAC-011-3 because they don't apply to the Operations Horizon.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
NIPSCO is concerned that the requirement does not provide adequate assurance that the RC will respect the ratings established by the TO or the TO's FAC-008 methodology. As written, the language is vague and could be interpreted as allowing an RC to determine the ratings that a TOP must use (including normal and emergency ratings and seasonal changeover dates) without respecting the TO's authority to establish such Facility Ratings.	
Likes 0	
Dislikes 0	
Response	

3. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.3 and R2.4, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP recommends retaining the clarifying language of 2.3 and 2.4. Having the options explicitly stated within the standard ensures consistency throughout each RC area in the way TOPs respond to Contingencies. Having those clear, well-defined options spelled out within the RC's SOL Methodology enhances reliability by setting consistent expectations of what actions neighboring or overlapping TOPs may be performing. Furthermore, it is valuable to house the language within a standard dealing with the Operations Planning Horizon, to avoid a potential misconception that the described options are only permissible when planning the system in the Near-term or Long-term Planning Horizons.	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	No
Document Name	
Comment	
See response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more	

clarity on the intent for this requirement.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

Comment 1: CHPD is concerned about the ‘permitted uses’ language of RAS and other schemes, to be contained in the RC’s methodology. In the TPL / Planning process, an entity may determine and build a scheme under a certain set of assumptions (how the system was planned / designed / built). The entity may determine this scheme is acceptable to their own operations. The RC may then prohibit the use of this non-RAS in the RC’s SOL methodology, rendering the scheme useless for actual operations. CHPD has witnessed this concern with one of its neighbor’s automatic schemes and feels that the prohibition of the scheme’s use for operations has not always been in the best interest of system reliability. CHPD also recognizes the Planning Coordinator and Reliability Coordinator will be performing additional coordination through the new PRC-012-2, whose purpose is stated as “To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System

(BES).” The requirement here in FAC-011 may be duplicative of those objectives found in the new PRC-012-2.

In FAC-011-3, only allowed uses of Remedial Action Schemes was listed under the RC’s methodology requirements. In FAC-011-4, the addition of ‘other automatic post-Contingency mitigation actions’ adds significant scope to the methodology. CHPD wants the Standard Drafting Team to ensure that the concept of ‘operated as designed’ is maintained in the use of these other automatic post-Contingency mitigation actions.

Comment 2: In the discussion about UFLS being not permitted in R4.6 (and by omittance, UVLS being permitted) CHPD identifies that there seems to be confusion, or at least the potential for confusion, about the FERC order and acceptable use or non-use of these schemes. The first point is that there is a difference between a UFLS or UVLS program. From the NERC glossary of terms:

Undervoltage Load Shedding Program: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Underfrequency Load Shedding Program is not described in the NERC glossary of terms, but is described in the purpose description for PRC-006:

To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures

A UFLS or UVLS program is a coordinated use of UFLS or UVLS relays at multiple locations and are essentially used to prevent described conditions that are essentially the events of an IROL. The FERC order 818 states regarding UVLS programs:

“We conclude that UVLS **programs** (emphasis added) under PRC-010-1 are examples of such “safety nets” and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies.”

Again, in the “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations”, on page 109 in the discussion about UFLS as a safety net, it simply states:

Safety nets should not be relied upon to establish transfer limits

CHPD would like clarification here in the proposed FAC-011-4 whether the references to UFLS (and UVLS) are meant to be to the UFLS (PRC-006) and UVLS (PRC-010) Programs or is it a reference to something else.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak agrees that BES performance is adequately covered and that no reliability gap is introduced with the removal of the requirements R2, R2.3 and its subparts, and R2.4. Peak agrees with the justifications set forth in the FAC-011 mapping document for these requirements. Peak believes that the "rules" set forth in the current FAC-011-3 R2, R2.3 and its subparts, and R2.4 have relevance in the TPL standards, but not in the TOP or IRO standards. When planners plan the system, they are constructing a system that meets the performance requirements set forth in TPL-001-4. This system is then provided to operators to operate. Rules such as those reflected in Table 1 of TPL-001-4 and the footnotes of Table 1 are important for identifying Corrective Action Plans associated with determining how the system is to be built; however, Peak believes the "rules" as reflected in FAC-011-3 R2, R2.3 and its subparts, and R2.4 are not necessary for operating the system. Operators encounter many operating scenarios that were not addressed or anticipated in the TPL Planning Assessments, and very often these conditions are more severe than those assessed in the Planning Assessments. Peak agrees with the SDT's assertion that operators need the flexibility to operate the system to address SOL exceedances without being confined to such "rules" regarding non-consequential load loss, interruption of firm transmission, and requirements associated with preparations for the next Contingency. All of these items are expected to be addressed as needed in associated Operating Plans. Accordingly, operators do not need to be confined to these "rules" set forth in current FAC-011-3 R2, R2.3 and its subparts, and R2.4.

Likes 0	
Dislikes 0	

Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy would like to point out to the SDT, a potential typo in the FAC-011-3 Mapping Document. When referencing the translation of R2 and its sub-requirements to a New Standard or Other Action, the SDT appears to reference a TOP-012-3 standard R14. We believe that this was in error, and that perhaps the drafting team meant to reference TOP-001-3 instead.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We think the removal of BES performance from R2 is relevant, but that the performance requirements associated with determination of stability limits associated with SOLs are vague compared to the TPL assessments. Is the SDT intent to let full flexibility to the RC with regards to stability performance requirements per requirement 4.1? For example, is a unit pulling out of synchronism something up to the RC to demonstrate as acceptable for the purpose of determining SOLs/IROLs for a given interface?	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
The existing TOP standards adequately cover BES performance.	
Likes 0	
Dislikes 0	
Response	

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	

Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

4. Are there any reliability objectives of FAC-011-3, Requirement R2, R2.3 and R2.4 that you maintain need to be preserved in requirements relating to the development of Operating Plans which would reside outside the FAC family of standards? Please explain your response.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
As a practice, reliability objectives should be maintained in standards. Documentation and examples supporting those objectives (white papers, guidelines, etc.) can reside outside the standard. Regarding Operating Plans, the definition found in the NERC glossary of terms is sufficient for CHPD. Regarding R2, R2.3 and R2.4 as it deals with the response of the system to events, any other reliability objectives should be contained in the standard to ensure these items have the scrutiny, review, and due process related to these items. CHPD has mentioned some concerns in its responses to item #3, but has nothing in addition to those to add here.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Peak believes that the “rules” set forth in the current FAC-011-3 R2, R2.3 and its subparts, and R2.4 have relevance in the TPL standards, but not in the TOP or IRO standards. When planners plan the system, they are constructing a system that meets the performance requirements set forth in TPL-001-4. This system is then provided to operators to operate. Rules such as those reflected in Table 1 of TPL-001-4 and the footnotes of Table 1 are important for identifying Corrective Action Plans associated with determining how the system is to be built; however, Peak believes the “rules” as	

reflected in FAC-011-3 R2, R2.3 and its subparts, and R2.4 are not necessary for operating the system. Operators encounter many operating scenarios that were not addressed or anticipated in the TPL Planning Assessments, and very often these conditions are more severe than those assessed in the Planning Assessments. Peak agrees with the SDT's assertion that operators need the flexibility to operate the system to address SOL exceedances without being confined to such "rules" regarding non-consequential load loss, interruption of firm transmission, and requirements associated with preparations for the next Contingency. All of these items are expected to be addressed as needed in associated Operating Plans. Accordingly, operators do not need to be confined to these "rules" set forth in current FAC-011-3 R2, R2.3 and its subparts, and R2.4.-

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SRP Recommends retaining the language of R2.3 and R2.4 within the FAC-011-4 standard.

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	No
Document Name	

Comment

Reclamation supports the changes to the requirements because no gaps were identified as the result of the changes.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA has reviewed R2, R2.3 and 2.4 and believes the TOP-001-4 and TOP-002-4 requirements are sufficient.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
The revised TOP and TPL standards cover the planning and operations of the system.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	

National Grid supports the NPCC RSC Group comments. Additional comment for consideration: Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition could be revised to state "Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded".

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed

Answer	Yes
Document Name	

Comment

We think actions allowed in real-time operations should not be part of FAC-011, but captured by TOP/IRO standards. We think there is ambiguity and a lack of consistency in the industry around allowed system adjustments and preparation for the next contingency (old R2.4) with refers indirectly to N-1 situations. Although it is clear that FAC-011 requires, at a minimum, to consider a set of single contingencies to address stability limits, it is not clear at all what are the minimum requirements applicable if the contingency was to occur… and how "preparing for the next contingency" is addressed by the current standards.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

5. Do you agree that the SDT should allow the use of UVLS in the establishment of stability limits? If not, please explain and provide alternative language.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

It is unclear in 4.6 (and the entirety of R4) if "stability limits" refers to either or both of the following (1) bulk transfer across the BES (transfer limit stability studies) or (2) load areas (local area limit stability studies). BPA believes that it is important to distinguish between transfer limit stability studies and local area limit stability studies. We recommend that the SDT add language to R4 to clarify that R4 applies to only transfer limit stability studies. BPA believes that the SDT should not allow UVLS in transfer limit stability studies, unless it is part of a designated RAS. We understand that FERC is describing transfer limit stability studies in Order 818. BPA therefore does not think that relying on UVLS, except where included in RAS, to increase transfer limits is appropriate. However, BPA believes that the SDT should allow UVLS in local area limit stability studies when failure of the UVLS would not result in cascading. If UVLS is not allowed in local area limit stability studies, the TOP may be forced to perform pre-contingency load shed.

Proposed: Planned use of UFLS or UVLS in establishment of stability limits is not allowed unless either of the following conditions is true:

- Pre-contingency load shedding would be required in order to meet BES performance criteria
- Load shedding is already included as part of an approved Remedial Action Scheme

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

UVLS is a safety net. It should not be used as an acceptable tool to preserve acceptable system performance for credible contingencies unless it is part of a RAS. This is directly implied in FERC order 818. The wording should be: "R4.6 Describe…; neither the planned use of underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) is allowed in the establishment of stability limits."

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation has concerns with possible misinterpretation of FAC-011-4 R4.2 and R5 as it implies Real-Time Assessments will include Stability. Reclamation also does not agree with the identified single Contingency and multiple Contingencies for use in determining stability limits because the TOP will inform the RC which Contingencies are credible.	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
UVLS is a safety net. It should not be used as an acceptable tool to preserve acceptable system performance for credible contingencies unless it is part of a RAS. This is directly implied in FERC order 818. The wording should be: "R4.6 Describe…; neither the planned use of underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) is allowed in the establishment of stability limits."	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
UVLS should remain a safety net and not be relied upon to provide acceptable system performance even for N-1-1 or N-2 contingencies.	

Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") does not agree that the SDT should allow the use of UVLS in the establishment of stability limits. CenterPoint Energy believes that UVLS, like UFLS, is a "safety net" that is deployed as a preservation measure to maintain the reliability of the BES. UVLS should not be relied upon to establish limits in a planning environment, regardless of horizon.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
These comments are duplicated from comments made on question #3 above. CHPD would note that the language stated in the NERC summary from the 2003 report uses the term 'transfer limits', whereas in this SOL revision document it is described as 'stability limits'. These two terms have different meanings, and the reference in the SOL document should be reviewed.	

In the discussion about UFLS being not permitted in R4.6 (and by omittance, UVLS being permitted) CHPD identifies that there seems to be confusion, or at least the potential for confusion, about the FERC order and acceptable use or non-use of these schemes. The first point is that there is a difference between a UFLS or UVLS program. From the NERC glossary of terms:

Undervoltage Load Shedding Program: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Underfrequency Load Shedding Program is not described in the NERC glossary of terms, but is described in the purpose description for PRC-006:

To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures

A UFLS or UVLS program is a coordinated use of UFLS or UVLS relays at multiple locations and are essentially used to prevent described conditions that are essentially the events of an IROL. The FERC order 818 states regarding UVLS programs:

"We conclude that UVLS **programs** (emphasis added) under PRC-010-1 are examples of such "safety nets" and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies."

Again, in the "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", on page 109 in the discussion about UFLS as a safety net, it simply states:

Safety nets should not be relied upon to establish transfer limits

CHPD would like clarification here in the proposed FAC-011-4 whether the references to UFLS (and UVLS) are meant to be to the UFLS (PRC-006) and UVLS (PRC-010) Programs or is it a reference to something else.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
UVLS should remain a safety net and not be relied upon to provide acceptable system performance even for N-1-1 or N-2 contingencies.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No

Document Name	
Comment	

We agree with FERC, Undervoltage load-shedding schemes (UVLS) are a “safety net” and should not be a tool used by Bulk Electric System operators in the derivation of stability limits. In some areas single contingencies include bus faults, stuck breakers and tower-contingencies.

Note: ERCOT does not support this response.

Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	No
Document Name	
Comment	

Not sure how the SDT like entities to vote. The SDT rationale indicated that their understanding of FERC Order 818 prohibited the use UVLS in the establishment of stability limits for N-1 contingency. Hence, if the SDT understanding of the FERC order is correct that FERC doesn’t allow use of UVLS in the establishment of stability limits for N-1 contingency then it would also mean that using UVLS is also prohibited for N-2 contingencies. Indicating a “Yes” to Question 5 is contradicted to FERC Order 818. Indicating a “No” to Question 5 is in alignment with the SDT understanding of FERC Order 818.

Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the allowed use of UVLS assuming that its meaning is not restrictred to the defined term UVLS Program and is used as an umbrella term that also includes local UVLS schemes. We would disagree if UVLS was intended to be synonymous with UVLS Program, since it would imply that use of local UVLS is not allowed. This illustrates the need to clarify what is the intended scope of UVLS in this standard.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
A stability limit may arise due to any type of multiple contingency (R5.3 and R5.4). UVLS should be a permissible mitigation method to either eliminate or increase stability limits such that transfers are not unduly constrained.	
Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Consistency is necessary between the mitigating actions permitted to maintain acceptable performance after N-1-1 and N-2 Contingencies in the Planning Assessment and Real-time Operations. The use of equal more limiting parameters prescribed in FAC-015-1 R1-R3 would be undermined by the prohibition of UVLS in response to more severe Contingencies when calculating SOLs.

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Peak agrees that UVLS should be allowed for use to prevent adverse reliability impacts for Contingencies more severe than single P1 Contingencies and that such allowances should be addressed in the RC's SOL Methodology. However, Peak is concerned that the use of UVLS, RAS, and other automatic post-Contingency mitigation schemes are confined to the development of stability limits. Peak believes that the allowed use of RAS or other automatic post-Contingency mitigation actions should be extended beyond the establishment of stability limits to also apply to the development of Operating Plans in general. Because the current FAC-011-3 intermingles "how to operate the system" with SOL establishment, it can be argued that the current FAC-011-3 already allows the RC's SOL Methodology to extended beyond the establishment of stability limits to also apply to the development of Operating Plans. While Peak is supportive of the SDT's attempt to focus FAC-011-4 more on establishing Facility Ratings, System Voltage Limits, and stability limits used in operations and removing the aspects of FAC-011-3 that relate more to "how to operate the system", it seems the SDT inadvertently introduced an inconsistency by limiting the use of RAS (or automatic actions) for deriving stability limits only. Peak believes the RC should have the ability to determine the use of RAS and other automatic post-Contingency mitigation actions across the board – not just for stability limit establishment. This issue, however, does not seem appropriate to be addressed in the FAC family of standards.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	

Comment	
Given that FERC Order 818 clearly addresses the prohibition of using UVLS for calculating SOLs for single N-1 Contingencies, the SDT should consider a footnote within FAC-011-4 Part 4.6 that recognizes the FERC Order 818's prohibition on the use of UVLS in the determination of N-1 stability limits.	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA appreciates the SDTs efforts to provide the background and historical context of UVLS and the derivation of IROLS. Unfortunately the background information provided is confusing and does not make clear what the SDT is trying convey. The rational appears to try and draw a line between UFLS and UVLS when in fact they perform the same function, but for different quantities. The use of UFLS is allowed in certain PC studied events and we see no reason why UFLS shouldn't be used where appropriate. We agree that UVLS should be considered in the establishment of stability limits; however we also believe UFLS should be allowed under certain scenarios as it is in the planning horizon.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
UVLS is allowed to maintain system performance for some contingency events as described in Table 1 of standard TPL-001-4. The RC allowed use of UVLS should not conflict with standard TPL-001-4.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We agree with the allowed use of UVLS under certain conditions, but we strongly disagree with the way the SDT has addressed the allowed use of UFLS and UVLS in the new FAC-011. Since R5 gives some flexibility to the RC to choose its method for considering various types of contingencies (N-1, N-2, etc.) for both OPA/RTA and stability limits, the acceptable actions in R4.6 should not be limited as they can vary a lot depending on the types of contingencies considered. For example, a RC considering only the minimum single contingencies from R5.1 may not be allowed to use UFLS and UVLS actions for N-1… but another RC may choose to establish stability limits and limit transfers accordingly to address more stringent and rare multiple contingencies for which additional means like the action of UFLS/UVLS may be allowed (if that same RC would choose not to plan a stability limit for those contingencies, it would be acceptable to use UFLS/UVLS as a safety net?). Similarly, the reference to UVLS in SVL requirement R2 is not adequate, as SVL may comprise multiple levels, some for acceptable for single contingencies (without UVLS), some with some UVLS actions allowed for multiple contingencies. We think that the consequence of the action (e.g. the use of non-consequential load loss as in TPL) should be used throughout the standards to allow the use of actions for specific contingencies (rather than referring to RAS, UFLS or UVLS).	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

In the case of non-IROL SOLs we agree. However, it was noted that according to the background information above and in FAC-11-4, the use of UVLS is only considered in the context of establishing stability limits as per Requirement R4 Part 4.6.

The use of UVLS should also be acceptable to respect Facility Ratings and System Voltage Limits.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	Yes
Document Name	

Comment

National Grid supports the NPCC RSC Group comments.

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	Yes
Document Name	

Comment

The establishment of stability limits must take into account automatic actions, including RAS and UVLS, since the loss of load can negatively impact system and unit stability performance. The SDT is correct in including this language in the proposed revisions.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT asserts it is not appropriate to use UVLS for the purpose of increasing transfer capability for stability limits for N-1 Contingencies. However, it may be appropriate to use UVLS to determine the post-contingency impact in regards to establishment of an IROL vs. an SOL. It may also be appropriate to use UVLS in determining whether or not pre-contingency load shedding is warranted.

Likes 0	
Dislikes 0	

Response

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Julie Hall - Entergy - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

6. If you have any other comments that you haven't already provided in response to questions 2-5, please provide them here.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT suggests rewording proposed R2 to clarify that the SOL methodology establishes a method for determining which of the Facility Ratings provided by the owner should be used in operations, and not a method for establishing Facility Ratings. Please see the suggested language below.

"R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ***which of the*** applicable owner provided Facility Ratings ***are*** to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

With respect to R3.5, the meaning of the phrase "Address the use of" is unclear. The meaning of this phrase could be interpreted several different ways. ERCOT understands that the intent of the SDT is to ensure that, under the SOL methodology, the RC and its TOPs have a method to determine how the common set of System Voltage Limits between the RC and TOPs are to be used in operations, without becoming overly prescriptive in the requirement language. ERCOT suggests rewording proposed R3.5 to "Address how the Reliability Coordinator and its Transmission Operators use common System Voltage Limits in the Reliability Coordinator Area;"

ERCOT notes that parts 4.1.1.-4.1.4. of R4 list the *minimum* stability performance criteria that should be used in the method to determine stability limits in operations. To add clarity, ERCOT suggests adding a new part 4.1.5 that reads ***"other stability performance criteria as required by the RC's SOL Methodology."***

****Please refer to the attached comment form for redlined language.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	
Comment	

Requirement R7 of the proposed FAC-011-4 standard requires the RC to define the method and periodicity a TOP must communicate their SOLs back to the RC. In comparison, parts 5.3-5.5 of requirement R5 of FAC-014-3 identify such communications must occur on a mutually agreed upon time frame. We believe Requirement R7 should be changed to a mutually agreeable timeframe that reflects the frequency a Transmission Operator will

conduct its Operational Planning Analyses and Real-time Assessments.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	
Document Name	
Comment	

ATC has the following concerns with the proposed FAC-011-4 standard.

- R3.1: Requirement R3.1 contains the term "stations" and uses an unconventional designation of "buses/stations".
    - The NERC BES definition does not require entities to identify BES stations, which would make it problematic to use the requirement as written.
    - Additionally, "buses/stations" is an unclear designation where entities may understand that System Voltage Limits shall be created for all Facilities in a station, including both BES and non-BES Facilities in that station. We do not believe this is the intent of the SDT so this should be clarified.
    - Consider modifying R3.1 language to state "Require that BES buses have an associated System Voltage Limit except for the BES buses that may be excluded as specified in the [RC]'s SOL methodology."
- R3.2: Clarify R3.2, similar to R2 language, that "respect[ing] the Facility voltage Ratings" means determining the "applicable owner-provided Facility" voltage "Ratings to be used in operations". FAC-008-3 R2 and R3, in conjunction with the NERC "Facility Ratings" definition, requires the Generator Owners and Transmission Owners, respectively, to have voltage ratings for Facilities.

- R4.5 and a New R5.5: Requirements R4.2, R4.4, R4.5 and R5 become applicable to all TOPs through proposed FAC-014-3 R2.

    - Given the language of R4.4, which requires "instability risks" to be "identified", ATC believes the standard overreaches at R5 when it includes stability analysis within OPAs and RTAs as determined by the RC. TOP-001-3 R13 and R14 and TOP-002-4 R1 already require the TOP study SOLs in RTAs and OPAs, and inclusion of OPAs and RTAs in R5 is redundant with TOP-001-3 and TOP-002-4. The TOPs are the local experts on the stability of their systems and the R5 requirement language should not force additional stability analysis beyond TOP-001-3 and TOP-002-4 in the OPA and RTA on to a TOP if stability is not an issue for its system. ATC recommends striking “and performing Operational Planning Analysis (OPAs) and Real -time Asses

      A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read:

      "R5.5 The applicability of the identified single Contingency and multiple Contingencies to its TOPs for use in determining stability limits."

    - Similarly, given the applicability of the model requirements stated in R4.5 to the TOPs performing stability studies under the RC SOL methodology, through FAC-014-3 R2, clarify is needed that a TOP does not need to have a model of similar scale or scope as the RC will use. Per TOP-003-3, TOPs determine what data is needed to perform their OPAs and RTAs and the scope of this data is likely a subset of the RC's data, whether covered by IRO-010-2 or proposed FAC-011-4 R4.5. The revision should make it clear that the breadth of the RC's model does not necessarily need to be replicated by the TOP.

      A proposed revision to R4.5 to address this concern would be the addition of the following language to the current proposed R4.5 language:

      "… necessary to determine different types of stability limits, including applicability of the model detail to studies performed by its TOPs"

- New R4.x: The RC SOL methodology should include how "impacted" PCs and TOPs will be identified for stability SOLs. The "impacted" language appears in FAC-014-3 R4 and R5 and clarity is needed for all parties.

- R7: The second sentence of R7 should be struck as it is a redundant requirement to IRO-010-2 R1. SOL communication should be a part of the RC's data specification, which already contains a requirement regarding periodicity of communication.

R8: The requirement should contain a minimum notice provision to TOPs, such as "30 days prior to implementation". The current language would permit an RC to issue a revision the day prior to a material change in its SOL methodology, possibly impacting a TOP's compliance under FAC-014.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	

Comment

This standard in its current form allows a single entity the ability to dictate operating and effectively planning criteria. PNM believes that the development of the SOL methodology should be a joint effort including RCs, TOPs, and PAs.

Propose revised R1 language: Each Reliability Coordinator, in conjunction with each of its Transmission Operations and Planning Coordinators, shall develop a methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area.

PNM believes that R2 gives the RC the ability to dictate how an entity uses its own Facility Ratings effectively modifying FAC-008. There is no point for an entity to establish a Facility rating that cannot be used when operating the system. PNM recommends removal of R2 and revision of FAC-008-3 to address any concerns regarding a lack of common facility ratings methodology.

PNM questions the reliability basis for R3.3. PNM believes that there may be legit reasons to have the UVLS settings higher than the limits for certain critical contingencies. FERC order No. 818 specifies not using UVLS for N-1; however, this requirement doesn't have that qualifier. If the SDT feels this concept should be included in the standard the requirement should move under R4.6 and shall clearly specify that it is only applicable to single contingencies.

PNM finds no difference between R6.1 and R6.2.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

1. FAC-11-4, Requirement R3.3 should be clear that it's only pre-contingency System Voltage Limits which should be above in-service UVLS scheme settings. When depending on these schemes, a post-contingency System Voltage Limit may fall below a UVLS set point.

2. FAC-11-4 Requirement R3 Part R3.4 should either be revised or removed. Identifying the lowest allowable System Voltage Limit does not make sense from the context of minimum voltage SVLs (it should be the highest SVL identified). Perhaps "lowest" could be replaced by "most restrictive".

3. Where FAC-11-4 Requirement R3 Part 3.7 requires coordination between adjacent RCs for SVLs the FAC-11-4 Requirement R2 and R4 are

silent on this with respect to Facility Ratings and stability limits. The RC should also be coordinating Facility Rating and Stability SOL actions with RCs within an Interconnection where applicable and this should be spelled out in FAC-11-4.

4. FAC-11-4 Requirement R4.1.2 should not force Reliability Coordinators into adopting transient voltage response criteria as part of their SOL Methodology. There are effective alternative means to guard against coincidental load loss and inadvertent tripping such as employing a relay margin criterion instead. Please remove or modify the requirement to recognize viable alternatives exist.

5. FAC-11-4 Requirement R4.1.2 should not force Reliability Coordinators into adopting transient voltage response criteria as part of their SOL Methodology. Transient voltage criterion results should be communicated to the Reliability Coordinator as outlined in FAC-15-1 Requirement R6 for consideration.

6. FAC-11-4 Requirement R4.1.3 introduces the term "angular stability". Why is System damping considered separately? Angular stability consists of Transient Stability and Small Signal Stability, System damping would be part of Small Signal Stability.

7. FAC-11-4 Requirement R4.4 appears to ask for so much detail in the SOL Methodology (FAC-11-4 Rationale indicates enough information should be provided to duplicate the study) that it would be extremely onerous to satisfy given that the assumptions made for each operating zone of our RC area are vastly different given the common conditions and risks that exist. Detailed assumptions around instability risks, transfer levels, dispatch and system conditions are better left in study documentation pertaining to each specific zone. (Also see 5 below. We believe that there is value in sharing SOLs and associated study reports based on need/request.)

Additionally, the phrase "instability risks are identified" is misleading and does not really contribute to the objective of the requirement/standard. We assess that the intent of R4 is to present the method for determining stability limit, not to identify risks although they are the driver for developing stability limit. If the intent of that phrase is to present the stability concerns and/or the way to address such concerns through SOL determination, then we offer the following revised wording:

"Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and the applicable System conditions including any changes to System topology such as Facility outages;"

8. FAC-11-4 Requirement R4.5 asks for a description of the critical details from other Reliability Coordinator areas necessary to determine stability limits. This is in conflict with FAC-14-3 R5 which no longer enforces that Reliability Coordinators *provide its SOLs and IROLs to those entities with a reliability need.* IRO-014-3 speaks to required information for Operating Plans, Procedures and Processes but does not address the need for critical details required for developing SOLs.

Furthermore, obtaining these critical details from other Reliability Coordinators and verifying their impact to SOLs through study can require a great deal of time and effort. It is recommended that more than 12 months be given in order to comply with this requirement. An appropriate time would be in the order of 24 – 36 months.

Obtaining these critical details would also be made much easier and the information would be much more valuable if all Reliability Coordinators (RC) were aligned in respecting the same set of contingencies and performance criterion for IROLs. For example, if an RC finds an instability issue due to a multiple contingency in a neighboring RC's footprint there's no requirement in FAC-11 and FAC-14 that supports forcing the neighbor to respect that contingency in the interest of interconnected system reliably as multiple contingencies are still left up to the RC's discretion.

9. FAC-11-4 Requirement R5.2 leaves the door open for any potential contingency to be considered credible and will create an unnecessary burden in attempting to show compliance. Listing other specific single contingencies that could be deemed credible would improve this requirement.

An alternative to listing additional specific contingencies would be to revert to the existing language in FAC-11-3 Requirement R2.2 which specifies, at a minimum, which contingencies must be respected.

10. FAC-11-4 Requirement R6.2 is redundant with Requirement R6.1 in that a criterion is what is used to identify SOLs that are IROLs. Consider revising to combine the two sub-requirements to remove unnecessary duplication and confusion.

11. FAC-11-4 Requirement R8 requires RCs to provision of their SOL Methodology to other entities. Given that the changes to the FAC-11-4 standard require substantial documentation work on the part of many RCs, more time should be given for compliance. At least 36 months is recommended. Furthermore, given there will be changes coming to the IROL requirements in this very same standard maybe the compliance period should be extended to the compliance deadline associated with that version of the FAC-11 standard to avoid the burden of duplicating a great deal of work.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

FAC-011-4 Requirement R2 specifically states that the RC "shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations". It goes on to identify that the method "shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area". This requirement needs to be bounded such that the RC is not specifying in its methodology how a Transmission Operator and thus a Transmission Owner is required to rate its transmission facilities, up to and including the use of real time ratings. This would determine the amount of risk a Transmission Owner is subject to for its facilities. The standard should only specify the end objective and not the process to achieve that objective.

FAC-011-4 Requirement R3.2 introduces the concept of "Facility voltage Ratings". This is not a defined term and leaves room for interpretation. There is no standard that requires TO's to provide Facility Ratings for voltage. Before TOP's are required to operate to Facility Ratings for voltage there should be a requirement for TO's to provide Facility Ratings for voltage.

FAC-011-4 Requirement R4 seems to be somewhat duplicative of TPL-001-4 requirements R5 and R6. Consideration should be given to coordination of these requirements.

FAC-011-4 Requirement R5 includes language that requires the RC's SOL Methodology to include "the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPA's) and Real-time Assessments (RTA's)". Use of SOL's in OPA's and RTA's is covered in TOP-001 and TOP-002. The concept of requiring how SOL's should be used in OPA's and RTA's should be removed from this requirement.

FAC-011-4 R7 is redundant with IRO-010-2 R1. As the SDT notes in its preface to FAC-011-4, SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R7 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	
Document Name	

Comment

FAC-011 R3.1

We do not agree with Part 3.1 as written since it implies that all BES (i.e. each and every) buses/stations within an RC or TOP area need to have a SVL. To meet this requirement, an RC/TOP will need to determine and list a large number of System Voltage Limits (SVLs), many of which have no impact on the BES voltage performance and hence serve little or no value to the determination of SOLs and/or IROLs.

The proposed definition of SVL is:

The maximum and minimum steady -state voltage limits (both normal and emergency) that provide for acceptable System performance.

With this definition, we interpret that there may be more than one SVL within an RC or TOP area, and that the identified SVLs are the limiting parameters with which to assess acceptable voltage performance on an RC or TOP system and their interconnected systems. An RC or TOP may identify a handful of buses/stations within their areas to be requiring the stipulation of SVLs, while deeming it unnecessary to stipulate SVLs on other buses/stations as acceptable voltage performance can be assessed/assured by observing the stipulated SVLs.

We therefore suggest Part 3.1 be reworded as follows:

R3.1. Require the identification of the critical BES buses/stations and associated System Voltage Limits with which to assess acceptable System performance

FAC-011 R3.2

This part is not required. Observing the more restrictive of the two – SVLs and Facility voltage Ratings, is the general practice for any RCs and TOPs. If the SDT wish to spell out this requirement explicitly, we propose the following wording:

3.2 Require that the more restrictive of the System Voltage Limits and the Facility voltage Ratings at the same bus/station be respected.

FAC-011 R3.4

This part is not required since all applicable SVLs (may be more than one) identified in the proposed Part 3.1 will be observed in the determination of SOLs. Identifying the lowest allowable SVL serves little or no purpose, or can be insufficient, in the determination of SOLs.

We suggest deleting Part 3.4

FAC-011 R3.5,6,7

The overall intent of these parts is to ensure the methodology specifies the use of common SVLs by those entities that need to determine SOLs around those buses/stations for which SVLs are identified. This can be achieved by combining them into the following proposed part:

3.5. Address the use of common System Voltage Limits by all entities in the Reliability Coordinator Area and the process to coordinate the determination of System Voltage Limits between neighboring Reliability Coordinators and Transmission Operators.

FAC-011 R4.4

The phrase “instability risks are identified” is misleading and does not really contribute to the objective of the requirement/standard. We assess that the intent of R4 is to present the method for determining stability limit, not to identify risks although they are the driver for developing stability limit. If the intent of that phrase is to present the stability concerns and/or the way to address such concerns through SOL determination, then we offer the following revised wording:

4.4 Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and the applicable System conditions including any changes to System topology such as Facility outages;

FAC-011 R5

We interpret R5 to require identification of relevant single Contingencies AND multiple Contingencies for use in determining stability limits, and in performing Operational Planning Analysis (OPAs) and Real time Assessments (RTAs), and any Planning Coordinator identified contingency events for use in determining stability limits. As such, and considering the umbrella wording in R5 and that Parts 5.1 to 5.3 essentially cover all contingency events, we do not see the need for Parts 5.1, 5.2 and 5.3. To add clarity, we propose R5 be revised, to include Part 5.4, as follows:

R5 Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits, and in performing Operational Plans Analyses (OPAs) and Real time Assessments (RT the method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC 015 1, Requirement R6 to identify the Contingencies for use in determining stability limits.

Note: ERCOT does not support the response to Q6

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	
Document Name	

Comment

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed

Answer	
Document Name	

Comment

1- We support the harmonization and approach to the new standards for the establishment of SOLs. However, we do have an important concern regarding the way the use of UVLS and UFLS in the establishment of stability limits was incorporated in the FAC-011-4 requirements. Although the requirements give good flexibility to the RC in identifying the set of contingencies applicable for SOL determination, they also impose performance requirements (SVLs and limited use of UFLS/UVLS) that do not make any distinction between the mandatory single contingencies and the complimentary multiple contingencies. Since the RC has flexibility to identify the relevant contingencies beyond the minimum requirements from R5.1.1, it should also have flexibility in the performance requirements for the allowed use of mitigation actions.

2- We think the level of description in sub-requirements R3.X for System Voltage Limits is a burden without added benefit to reliability. Why so much details for SVL and not for Facility Ratings? R3.5-3.7 are not needed. If coordination is an issue, it should be addressed in a single requirement for the whole standard. R3.2 is redundant with the application of FR in R2. R3.3 is an issue that should be addressed with the allowed used of UVLS under certain circumstances, not captured by SVL requirements. Different SVLs may be used for different contingencies, not just N-1. R3.4 is redundant with SVL definition.

3- R4.2 is a redundant cross-reference with 4.1 and R5 and does not bring any benefit to the remaining of the standard. R4.3 also is redundant since the RC has to describe how stability limits are established per R4 whether or not multiple TOPs are involved.

4- Concerning the selection of contingencies, it is understood that the RC has full flexibility to determine the appropriate multiple contingencies for its System, correct? If that is the case, the proposed standard should allow the same flexibility for the performance requirements associated with those contingencies, namely the use of UVLS and UFLS.

5- Although we appreciate the standard's flexibility regarding the stability performance requirements in R4.1, there seems to be a lack of guidelines and minimum expected performance as in TPL (no mention of Cascading, instability, etc.).

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	
Document Name	

Comment

Comment 1: It is a common concept in industry that the system should be operated as it is planned. The TPL-001-4 standard is one of the main regulatory drivers to the planning of the system, while the FAC standards regarding SOLs are important to the operation. While not possible to align the two standards entirely, there are some features of the TPL standard which may have merit for the FAC-011 standard revision which have not been addressed in the draft of the proposed revision of FAC-011-4. These include:

1. Voltage Criteria (TPL-001-4 R5)
2. Instability Criteria (TPL-001-4 R6)
3. Division of responsibilities (TPL-001-4 R7)

The Voltage criteria is present in both FAC-011-3 and TPL-001-4. While TPL-001-4 voltage criteria requirement includes steady state, post-contingency deviation, and transient voltage response, the proposed FAC-011-3 criteria has additional performance metrics. This presents a risk where the system may not be operated as it was planned, because the criteria proposed in FAC-014-3 could be more conservative than the criteria required by TPL-001-4. The Standard Drafting Team should take this opportunity to consider aligning the operational criteria in the proposed FAC-011-3 with that of TPL-001-4. CHPD recognizes that due to the variety of unknowns encountered in real-time, operational criteria should have more flexibility than system planning.

Comment 2: CHPD is also concerned by the requirements in R3.6. and R3.7. regarding coordination of these system limits. This is not well addressed in the Standard Drafting Material as to the intent and scope of the proposed coordination. If the expectation is simply to share, post, or distribute limits, then that would be a helpful clarification. If the expectation is to conduct additional coordination studies involving multiple parties and the RC, then it is clearly a greater body of work and should be addressed further and clarified by the Standard Drafting Team as to the nature of these expectations.

CHPD is in favor of the removal of R3.6. and R3.7. altogether, because the coordination of these is already essentially performed through the use of the OPA and RTA.

Comment 3: The continued use of margins in FAC-011-4 (also found in FAC-011-3) is another instance of mis-alignment between TPL-001-4 and FAC-011-3. CHPD recognizes that there is value to include an assessment of margin in the operational realm, but is also aware that this is a difference in the way the system is planned vs. operated, and in some instances may result in the system being operated to support a particular margin that wasn't necessarily planned through TPL-001-4 or other planning standards. CHPD recognizes that due to the variety of unknowns encountered in real-time, operational criteria should have more flexibility than system planning.

Comment 4: Regarding the voltage criteria proposed in FAC-011-4 R4, there are a number of concerns.

1. The use of the term 'steady-state voltage stability' in 4.1.1. is confusing. Steady state analysis is different than stability analysis. Please clarify this term. If this is the feature described in the 2003 blackout report, this would be the assessment of reactive power support.
2. Angular stability criteria is a new metric to the FAC-011 standard; this concept is discussed to some extent in the 2003 blackout report as well. It is assumed that this is the analog to the FAC-011-3 requirement R1.2.4 "The system demonstrates *transient*, *dynamic*, and voltage stability" (emphasis added). CHPD would prefer the transient and dynamic language from FAC-011-3 to be maintained, rather than 'angular'. The system damping criteria in 4.1.4. and the transient voltage response in 4.1.2 could be also included as part of the angular (transient/dynamic) criteria, and does not need to be specifically enumerated.

If the Standard Drafting Team feels prescriptive requirements are required over performance based requirements, CHPD believes that this requirement could be simplified to something similar to "The Reliability Coordinator shall have voltage reactive margin criteria" and "The

Reliability Coordinator shall have stability criteria for a) transient voltage response, and b) system damping"

Comment 5: CHPD would also like to see a requirement for a definition of System Instability in the RC SOL methodology, analogous to the TPL-001-4 R6:

TPL-001-4 R6: "Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

CHPD finds the text of TPL-001-4 R6 adequate to incorporate into the proposed FAC-011-4, with the Transmission Planner and Planning Coordinator references updated to Reliability Coordinator. This is particularly important since the Reliability Coordinator is to identify IROLs, which are these types of system phenomena.

Comment 6: Requirement in FAC-011-3 R3.4 – "Identify the lowest allowable System Voltage Limit;" seems duplicative or redundant to the proposed definition of System Voltage Limit – "The maximum and ***minimum*** steady
System performance."

The System Voltage Limit, in itself, should be the minimum allowable system voltage.

Comment 7: There is no mention of steady state thermal performance in the requirements for the Reliability Coordinator SOL methodology, nor language stating that SOLs shall not exceed associated Facility Ratings for thermal ratings (as found in the old FAC-010-3 R1.2). CHPD strongly encourages the Standards Drafting Team to add language supporting the operation within thermal limits to the proposed FAC-011-4 document, possibly in the vicinity of R4, which discusses stability and voltage criteria.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

It is unclear by the wording of R4 whether Transmission Operators determine stability limits or the RC. Based on R2 and R3, it is clear that the Transmission Operators develop Facility Ratings and System Voltage Limits based on the RC methodology. Based on R7, it says SOLs are communicated to the RC. One can assume this includes the stability limits as well, but R4 could be spelled out as a TOP task to develop stability limits (unless the door is intentionally being left open for the RC to determine stability limits in parallel to the TOP). It should be the TOP developing all of the

SOLs and communicating them to the RC. The RC should only drive the methodology and determine which of the provided SOLs qualify as IROLs.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	
Document Name	

Comment

FMPA recommends a feedback loop be introduced to FAC-011-4 for the RC's SOL methodology, such as found in FAC-008-3 R5. This will provide for better coordination between the PC and the RC, improve the effectiveness of the RC's Stability assessment, and allow consideration of best Stability analysis practices within the RC's footprint.

It is not clear what the phrase "for use in performing OPAs and RTAs" as used in R5 is intending. Are just the RC's OPAs and RTAs required to use this list of contingencies, or are all entities performing OPAs and RTAs within the RC footprint required to use this list? It does not make sense for every TOP to use the same extensive list of contingencies, since they may not have a need to model the System beyond their immediate TOP area.

Additionally, as currently worded R5 requires Stability analysis to be run on all contingencies that qualify as P1 events under TPL-001-4, which would result in a tremendous amount of work, but very little beneficial insight. The ability to apply engineering judgement to select those events that are expected to result in more severe System impacts is needed.

FMPA sees the use of the term "normal clearing" (lowercase, but note that the capitalized, defined term is used in the bulleted list) in 5.1.1 as problematic. Breaker failure schemes meet both the definition of Delayed Fault Clearing and the definition of Normal Clearing as they are currently written. Is it the SDT's intent to require breaker failure be included when determining stability limits? If not, FMPA recommends changing "with normal clearing" to "without Delayed Fault Clearing".

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP Standard Review Group has a concern in reference to the drafting team intents for Requirement R2. From our perspective, this proposed language may suggest that the RC will receive the authority to tell the Transmission Owner how to determine their Facility Ratings. We would ask that the drafting team provides more clarity on the intent for this Requirement.

The SPP Standard Review Group has a concern that the drafting team has potentially created a new term by adding the term “voltage” between Facility Ratings. We recommend that the drafting team uses the proposed phrase “voltage Facility Ratings**. "**

The SPP Standards Review Group has a concern that the drafting team may have caused confusion by not including the actual FAC-011-3 Standard in the posted material. From our perspective, this creates an inconsistency and disconnection on what the drafting teams intents are for this project. For future reference, we would suggest the drafting team include all pertinent documentation to help provide clarity and demonstrate consistency on what their intents and goals are for the project.

The SPP Standards Review Group has a concern pertaining to the language in Requirement 6 Subpart 6.2. There is a confusion on which term “violating” or “Exceedance” should be used in the Subpart language. From our perspective, the drafting team has put a lot of emphasis on the term “Exceedance” as they have developed a definition for the term “SOL Exceedance” and we feel that the term “Exceedance” should be referenced in the language to promote consistency with the intents of the drafting team.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

The language in Requirement R3 Part 3.2 that refers to “Facility voltage Ratings” is problematic. Splitting a NERC-defined term (Facility Ratings) with voltage isn’t a good practice. Suggested language: “the maximum and minimum voltage Facility Ratings”.

WAPA has a concern regarding the wording for **FAC-011-4 R4** and **R5** and the linkage between**.**

As written R4 implies **required** Stability assessments in all OPAs and RTAs.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

{C}**4.1.** ….

{C}**4.2.** Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for

identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real -time Assessments (RTAs). The method shall include:

WAPA understands that was not the intent of the SDT and suggests this minor modification:

4.2. Require that ***identified*** stability limits meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 ***for OPAs and RTAs***. **(Or)**

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. And remove stability from the body of R5 and add a R5.5 (as initially suggested by the MRO-NSRF with WAPA's modification)

A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read: "R5.5 The applicability of the identified single Contingency and multiple Contingencies **as agreed to by** its TOPs for use in determining stability limits."

Lastly, it appears "additional" is missing from Requirement 5.3

5.3. Any ***additional*** types of multiple Contingency events identified for use in determining

stability limits, or for use in performing OPAs and RTAs.

Without it, R5.3 is redundant to the body of R5.

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections:

1. Violation Severity Levels

i. Requirement 8 VSL

a. The VSL for Requirement R8 references Part 8.4 but there is no Part 8.4 in the standard. ReliabilityFirst believes that the timing piece is now incorporated into the main R8 Requirement and suggest the reference to Part 8.4 be removed from the VSL

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	
Document Name	

Comment

We support the ISO RTO Council Comments.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1

Answer	
Document Name	

Comment

With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability

Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	
Document Name	
Comment	
Peak believes that requirement R5 should contain a subpart that requires the RC's SOL Methodology to include a description of the performance requirements for Contingencies more severe than the single Contingencies listed in part 5.1.1. In operations, the operating criteria for single Contingencies is often more stringent than that of more severe Contingencies such as breaker failure Contingencies or common structure Contingencies. Accordingly, some RC's only examine these more sever Contingencies for instability, Cascading, or uncontrolled separation, and they may not screen such severe Contingencies for thermal or voltage exceedances as described in the proposed definition of SOL Exceedance. The SDT could include a subpart 5.5 which states, "The minimum performance requirements for Contingencies more severe than those described in subpart 5.1.1."	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	
Document Name	
Comment	

With regard to the proposed Requirement R2, CenterPoint Energy believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. CenterPoint suggests the following language for the proposed Requirement R2:

“Each Reliability Coordinator shall include in its SOL Methodology a mutually agreeable method for Transmission Operators to determine the applicable owner provided Facility Ratings to be used in operations.”

With regard to the proposed Requirement R6.2, the existing legacy language uses the word “violating” in reference to an exceedance of an SOL that qualifies as an IROL. CenterPoint Energy recommends the SDT revise the wording so that there is no negative connotation to the context of the proposed requirement.

CenterPoint Energy suggests the following language for the proposed Requirement R6.2:

“R6.2 Criteria for determining when an SOL exceedance qualifies as an IROL and criteria for developing any associated IROL TV.”

Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	
Document Name	
Comment	

Not directly related to questions 2-5, the NERC SAR related to Project 2015-09 identified the need “to address the issues identified in the FAC PRRs related to the application of the IROL term.” The proposed FAC-011-4 does not appear to have addressed the consistent application of IROL and simply maintains the language from FAC-011-3.

Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

SRP appreciates the efforts of the SDT and supports how the proposed changes generally reduce redundancy and provide clarity in communications. The SDT has also made improvements in further linking the planning and operational limits. SRP also has some recommendations for the SDT:

In FAC-011-4 R1, SRP recommends retaining the phrase “documented methodology”.

In FAC-011-4 4.4, SRP recommends requiring a process for acknowledgement of new/changing stability limits by operational personnel.

Likes 0	
Dislikes 0	

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3

Answer	
Document Name	

Comment

With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.

Likes 1	Tay Sing On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5;
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	
Document Name	v4 LSPT Q7 attachment SOL, SOL Exceedance comments.docx

Comment

LSPT previously provided informal comments regarding the definition of “SOL Exceedance.” In response to question 7, separate attached comments proposed changes to R6 of proposed FAC-011-4 that are related to recommended changes in the SDT’s proposed SOL Exceedance definition. Those separate comments are attached to this question. Numbered paragraph 5 explains the recommended changes to R6.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	
Document Name	

Comment

R4.6 specifically does not allow the use of UFLS in the establishment of stability limits, which is acceptable for all single contingencies and multiple contingencies as define by P1-P7 events in Table 1 of TPL-001-4. However, R5.4 requires consideration of contingency events by the PC in R6 of FAC-015-1. It could be that the Planning Assessment identified Cascading following an extreme event even with UFLS included. It's unclear whether the RC will consider this a valid stability limit or not. There should be limits placed on the scope of R6 of FAC-015-1 to P1-P7 events to allow the exclusion in R4.6 to remain.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

The intent of Proposed R2 needs more clarification as to which entities are using the same rating, for example: RC & TOP? or RC & all TOPs for the same facility? Is the intent to have all TOP's under the same RC using the same ratings methodology?

The intent of Proposed R5.4 is unclear. We believe the Planning Coordinator should provide the established stability limit and the method by which the RC should assess the system against established stability limits. Maybe an example would help the understanding.

Proposed R8.1 needs to define under what circumstances a nonadjacent Reliability Coordinator would have a reliability-related need for the Reliability Coordinator's SOL Methodology.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	
Document Name	

Comment

While we agree with the changes to FAC-011, we will be voting “No” because of our problems with FAC-015. These changes to FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

The first sentence of FAC-011-4 R2 should be clarified as follows: “Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are applicable th d in operations.” The proposed clarification makes it more obvious that the SOL Methodology only determines which owner-provided ratings are applicable for use in operations.

FAC-011-4 R3.1: Requirement R3.1 contains the term "stations" and uses an unconventional designation of "buses/stations."

- The NERC BES definition does not require entities to identify BES stations, which would make it problematic to use the requirement as written.
- Additionally, "buses/stations" is an unclear designation where entities may understand that System Voltage Limits shall be created for all Facilities in a station, including both BES and non-BES Facilities in that station. We do not believe this is the intent of the SDT so this should be clarified.
- Consider modifying R3.1 language to state "Require that BES buses have an associated System Voltage Limit except for the BES buses that may be excluded as specified in the RC's SOL methodology."

R4.5 and a new R5.5: Requirements R4.2, R4.4, R4.5, and R5 become applicable to all TOPs through proposed FAC-014-3 R2.

- Given the language of R4.4, which requires "instability risks" to be "identified," ATC believes the standard overreaches at R5 when it includes stability analysis within OPAs and RTAs as determined by the RC. TOP-001-3 R13 and R14 and TOP-002-4 R1 already require the TOP study SOLs in RTAs and OPAs, and inclusion of OPAs and RTAs in R5 is redundant with TOP-001-3 and TOP-002-4. The TOPs are the local experts on the stability of their systems and the R5 requirement language should not force additional stability analysis beyond TOP-001-3 and TOP-002-4 in the OPA and RTA on to a TOP if stability is not an issue for its system. ATC recommends striking “and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)” from R5.

A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read: "R5.5 The applicability of the identified single Contingency and multiple Contingencies to its TOPs for use in determining stability limits."

Similarly, given the applicability of the model requirements stated in R4.5 to the TOPs performing stability studies under the RC SOL methodology, through FAC-014-3 R2, clarity is needed that a TOP does not need to have a model of similar scale or scope as the RC will use. Per TOP-003-3, TOPs determine what data is needed to perform their OPAs and RTAs and the scope of this data is likely a subset of the RC's data, whether covered by IRO-010-2 or proposed FAC-011-4 R4.5. The revision should make it clear that the breadth of the RC's model does not necessarily need to be replicated by the TOP.

A proposed revision to R4.5 to address this concern would be the addition of the following language to the current proposed R4.5 language: "… necessary to determine different types of stability limits, including applicability of the model detail to studies performed by its TOPs."

FAC-011-4 R3.2: the term used is “Facility voltage Ratings.” The defined term is “Facility Ratings.” Remove voltage or reword to say “Facility Ratings for voltage."

FAC-011-4 R6.2: The term "violating" relates to previous Standard. Suggest: "Criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL Tv."

FAC-011-4 R7 is redundant with IRO-010-2 R1. As the SDT notes in its preface to FAC-011-4, SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R7 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.

FAC-011-4 R8 does not specify how far in advance of the effective date of the SOL Methodology the RC must provide its SOL Methodology to other entities. With other standard requirements that Transmission Operators develop their SOLs in accordance with the RCs SOL Methodology, changes that would require a new determination of SOLs based upon the new methodology could take some time to develop. It is recommended that the RC provide its methodology at least 30 days prior to the effective date to give entities an opportunity to evaluate changes to the methodology and implement any changes necessary to their SOLs prior to the effective date of the new SOL Methodology. Without sufficient time a registered entity could find themselves in violation of standard requirements due to lack of time to make changes to SOLs according to the new methodology.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	
Document Name	

Comment

LES is concerned that Requirement R2 does not provide adequate assurance that the Reliability Coordinator will respect the Facility Ratings established by the TO, or the TO's FAC-008 methodology. As written, the language is vague and appears to allow the RC to determine the Facility Ratings and voltage ratings that a TO must use. Additionally, based on the NERC definition of Facility Rating, there is a potential conflict between System Voltage Limits and Facility Ratings as both can utilize voltage ratings. At minimum, consideration should be given to potential inconsistencies that may develop between FAC-011-4, FAC-008-3 and the definition of Facility Rating as a result of the project.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	
Document Name	

Comment

While we agree with the changes to FAC-011, we are voting “No” because of our concerns with FAC-015. These changes to FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response

Wendy Center - U.S. Bureau of Reclamation - 5

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli

Answer	
Document Name	

Comment

FAC-011-3 R2 and R3 add an additional translation layer on top of FAC-008 which already defines the determination of Facility Ratings. Could this additional translation allow for the RC to impose ratings and risk that the TO owning the facility is not willing to accept? An example is forcing the use of

dynamic ratings. The language in R3.3 that requires the System Voltage Limit to be higher than the UVLS setting nullifies the ability to use local UVLS schemes. There exist local UVLS schemes that have been planned to operate at the emergency low voltage limit to protect local load and meet TPL requirements for prior outage (N-1-1) conditions. Effectively disallowing the use of local UVLS schemes to achieve acceptable system performance was likely not the intent. We suggest modifying the R3.3 language to address this unintended consequence. Requiring the operating limit to be more restrictive does not align with FAC-015 philosophy where the planning limits should be more restrictive.

Likes 0	
Dislikes 0	

Response
Steven Mavis - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.

Likes 0	
Dislikes 0	

Response

7. The SDT is proposing to divide existing Requirement R1 of FAC-014-2 into three requirements in FAC-014-3 to clearly indicate which entities have the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) [the RC], System Operating Limits (SOLs) [the TOP] and stability limits that impact more than one TOP in its Reliability Coordinator Area [the RC] into proposed Requirements R1, R2, and R4, respectively. Do you agree with the proposed changes? If not, please explain.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA supports R1 and R2. However, BPA does not agree with breaking out R4. It should be the impacted TOPs' responsibility to coordinate, establish and agree upon the stability limits, not the RC's.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli

Answer	No
Document Name	

Comment

Xcel Energy feels that R2 should be expanded so that the RC has a role for SOLs that impact more than one TOP, similar to R4. The alternative would be for R4 to be expanded beyond "stability limit" to be more general SOL that impacts more than one TOP. An example would be an interface/path/flowgate that is thermal limited below its Facility Rating due to other thermal (or voltage) limited transmission facilities in multiple TOPs. This concern would likely be addressed if the revised SOL definition is approved and is effective simultaneously with the FAC standards - we recognize that the revised SOL definition makes it clear that the MW limit for an interface/path/flowgate is an SOL only if it is a stability limit.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NSRF is not convinced the RC's have the experience necessary to determine stability limits where the limits impact more than one TOP. Although it may make sense to designate the RC as responsible, historically this has been done by TOPs cooperating with each other to determine the limits. The concern is the RCs may not understand the nuances associated with all of their footprint.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

This is a helpful proposed clarification. However, in the definition of IROL from the NERC glossary an IROL is:

"A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Therefore, one must calculate what the SOL is first, before determining whether the SOL is an IROL. If the RC is not required to calculate SOLs, how will it be able to determine whether or not the SOLs are IROLs? CHPD would propose that both TOPs and the RC calculate SOLs, but only the RC has the duty to determine which SOLs are IROLs. This would be consistent with the current FAC-014-2 approach and ensure that the RC is calculating SOLs so it can identify which SOLs are IROLs. If the RC is not calculating SOLs, there is the potential risk that the RC could miss an SOL which should be classified as an IROL.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA appreciates the desire to clearly indicate which entities have the responsibility for establishing SOLs and IROLs, but believes additional clarity in FAC-014-3 is needed. First, it is not clear who has the responsibility to run the stability studies, or how often to run them. Another concern is that IROLs, SOLs, and stability limits are not mutually exclusive. Are TOPs precluded from identifying IROLs?

Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	No
Document Name	
Comment	
We agree with R1 and R2, but we don't see the need to specifically require the RC to establish stability limits per R4 when more than one TOP is impacted. This should be addressed through the determination of SOL/IROLs per R1 and R2 in FAC-014 and the requirement that the methodology from FAC-011 include the method for determining stability limits. There is an unnecessary redundancy.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Without stating requirements for performance criteria and assessment methodology for what SOLs qualify as an IROL, the roles of each entity in this matter remains unclear.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR agrees with R1 and R2 but proposes the following language for R4: Each Reliability Coordinator, in conjunction with the impacted Transmission Operators, shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	
Likes 0	

Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
ATC believes these changes are acceptable if the SDT adds a new requirement R4.x to FAC-011-4 as explained above in our comments to question #6 where we recommend a new requirement that requires the RC to identify how they will determine "impact[ed]" entities.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP does not object to R1 as proposed, we believe that Transmission Operators should be afforded opportunity to provide input into the process, even if not specifically designated within the standard.	
Likes 0	

Dislikes 0	

Response

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	

Comment
Peak agrees with the suggested approach. One point of clarification. Proposed requirement R4 states, “Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.” Peak interprets this language to allow the RC the flexibility to either calculate this type of stability limit itself (i.e., the RC performs the calculation), or to utilize a TOP-calculated stability limit as the “established” stability limit, provided that the RC and the impacted TOPs accept its use. Please confirm that Peak’s interpretation is accurate.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	

Comment
Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Comment
While Duke Energy agrees with the proposal of dividing the existing R1 into three requirements, we request the SDT to consider whether there is a reliability gap in allowing only the RC to establish IROLs. We recommend the drafting team consider the following: R2. Each Transmission Operator shall establish SOLs (including the subset of SOLs that are IROLs) for its portion of the Reliability Coordinator Area

consistent with its Reliability Coordinator's SOL Methodology.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

Provided that the RC is limited in its ability to usurp the Transmission Owners rights in determining how Facility Ratings are determined, which are major components in SOL determination, than this proposal is acceptable. If the RC is not limited, then this is not acceptable as the RC should not be given the latitude to determine the amount of risk a Transmission Owner will accept through setting their methodology in determining an SOL, specifically a Facility Rating. The standard should only specify the end objective and not the process to achieve that objective.

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gladys DeLaO - CPS Energy - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

8. Existing FAC-014-2, Requirement R5, R5.2 requires the Transmission Operator (TOP) to provide its SOLs to its Reliability Coordinator (RC) and Transmission Service Providers (TSPs) that share its portion of the RC Area. The SDT is proposing in Requirement R3 of FAC-014-3 to exclude the TSPs from that communication chain. Other requirements in existing standards (MOD-028-2, Requirement R7, MOD-029-2a, Requirement R4, and MOD-030-3, Requirement R2.6) require the TOP to provide the Total Transfer Capabilities (TTCs), Total Flowgate Capabilities (TFCs), along with supporting information and assumptions to TSPs. Because the TTCs and TFCs already reflect the impact(s) of any SOLs, the SDT deemed retention of the existing language unnecessary. Do you agree with the proposed change? If not, please explain.

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC agrees with the exclusion of TSPs from Requirement R3 of FAC-014-3.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with excluding the TSPs from the SOL communications path.	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
NPPD agrees with removing TSPs from the notification requirements. The remainder of the requirement is also redundant with IRO-010-2 R1. As SOLs are a necessary input for OPA and RTA, the communication of them is required in the RC's data specification. As a result, including them here is redundant and unnecessary. Yes, the RC needs to know about changes to SOLs. The mechanism to notify them already exists in the data specification required by IRO-010-2 R1.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports NERC urging FERC to adopt Docket Number RM14-7-000, Comments of NERC in Response to NOPR MOD-001-2 (Available Transmission System Capability).	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes the proposed changes would be beneficial and provide clarity.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento	

Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

9. The SDT relocated the reliability objectives of existing Requirement R6 of FAC-014-2 into Requirement R6 of proposed Reliability Standard FAC-015-1 such that all Planning Coordinator and Transmission Planner responsibilities will be housed within one standard. Do you agree with the proposed change? If not, please explain.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA does not see the need for a new planning standard. The objective could be better accomplished by moving the requirement to existing planning standards. The annual system assessment is required to be provided to the RC per NERC standard IRO-017-1. The RC is in a better position to communicate with affected TOPs in the RC area if instability or uncontrolled islanding is identified in the system assessment.	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees that the Planning Coordinator responsibilities do not need to be in FAC-014-2. Manitoba Hydro would prefer if the responsibilities are related to FAC-013 or TPL-001 that the requirements be housed in one of those standards rather than create a new standard.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	

Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC agrees with the retirement of FAC-010 and modifications to FAC-014-4 however does not believe that FAC-015 is necessary.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that this requirement should be placed in TPL-001 since it is related to the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCE finds the new SOL/IROL construct to be clearer and more useful. As the drafting team points out, Operations Time Horizon SOLs are not necessarily included in Planning Assessments required by TPL-001-4. SCE supports the reliability objectives established by FAC-015-1 and the relocation of these objectives from the in-effect FAC-014 to the proposed FAC-015.	
Likes 0	
Dislikes 0	

Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports having the planners’ requirements contained in one standard.	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1,	

5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

10. If you have any other comments that you haven't already provided in response to questions 7-9, please provide them here.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	
Document Name	

Comment

ATC has the following additional comments on proposed FAC-014-3:

- R3: The SDT should strike requirement R3 since the content of this requirement is already covered by NERC standard IRO-010-2 R1 (i.e. this information or data is needed by the RC to perform its OPA and RTA as covered by R1.1).

R4 and R5.2 through R5.4: The term "impacts" and "impacted" are used without definition. See ATC's comments to question #6 above about the need for a new sub-requirement under R4 of FAC-011-4 to ensure how impacted parties are identified is addressed in the RC's SOL methodology.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

National Grid supports the NPCC RSC Group comments.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

1. We believe it will be more efficient for RCs to make their SOLs available to impacted entities through automated mechanisms, such as an on-line database portal, rather than providing the information as proposed. The proposed expectation would require direct communication between the RC and the impacted entities that would be documented through electronic communications or voice recordings. This would be a compliance burden on all entities involved. Moreover, this approach could introduce a natural latency when the RC provides the SOL

information to external entities. This latency could impact a PC or TP who could have partially completed a Planning Assessment, only to find that the SOL data they used is outdated and that the assessment will need to be restarted. By pushing this information to an on-line portal, impacted entities can then pull the most current data set for monitoring and assessment purposes. We believe this change would convert the requirement to a more risk-based performance approach that shifts the focus of risk to the availability of the automated mechanisms.

2. We observe that part 5.4 is the only portion of this requirement that expects the RC to provide updated information to external entities. We ask the SDT to clarify this discrepancy in the other external entities identified in the requirement.
3. The proposed standard appears to miss the possible coordination between RC and an adjacent RC, particularly in the instance that an impacted TOP from an adjacent Reliability Coordinator Area would need information related to SOLs. There currently is no obligation listed under Requirement 5 that captures this instance.
4. We ask the SDT to move the IROL-related critical information to Requirement R1 where the RC is obligated to establish the IROL. The references listed under Requirement R5 are confusing, as they only pertain to the PC.
5. For part 5.4, we believe the RC should provide the value of the stability limit or IROL, as identified in part 5.2.1, to an impacted TOP within its Reliability Coordinator Area.
6. We believe Requirements R1 and R6 should be combined, as there is no expected timeframe identified when a RC is required to provide a list of generation or transmission Facilities that are critical to the derivation of the IROL. Transmission Owners ad Generation Owners could have compliance implications if the information is not provided in a timely fashion. The provision of this information should be done as soon as the IROL is established.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Comments: ERCOT provides the following additional feedback:

FAC-014:

ERCOT suggests the following clarification to R4 to simplify the language and to avoid the possible interpretation that the RC's authority (or duty) to establish stability limits that impact multiple TOPs would only be triggered in the event one or more TOPs has preliminarily established such a stability limit pursuant to its obligation under R2:

R4. Each Reliability Coordinator shall establish ***any*** stability limit to be used in operations ***in accordance with its SOL Methodology if that*** limit impacts more than one Transmission Operator ***in that*** Reliability Coordinator Area.

****Please refer to the attached comment form for redlined language.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

1. FAC-14-3 Requirement R5 no longer enforces that Reliability Coordinators *provide its SOLs and IROLs to those entities with a reliability need.* IRO-014-3 speaks to required information for Operating Plans, Procedures and Processes but does not address the need for critical details required for developing SOLs such as study reports and other related operating documentation. This information is necessary in order to satisfy requirements in FAC, TOP and IRO standards where there's potential impact to neighboring RC areas.

Furthermore, obtaining these critical details from other Reliability Coordinators and verifying their impact to SOLs through study can require a great deal of time and effort. It is recommended that more than 12 months be given in order to comply with this requirement. An appropriate time would be in the order of 24 – 36 months.

2. FAC-14-2 Requirement R6 had been the one requirement tying identification of multiple contingencies in the Planning Horizon to those that must be considered in Operations. This requirement had ensured that if instability as a result of a multiple contingency was identified in the Planning Assessment then that contingency should be deemed credible. It was the best vehicle to use to influence another RC/TOP area within the Interconnection to recognize a multiple contingency within its area if shown to impact other areas. In the interest of both assistance in respecting an IROL and operating a more reliable interconnected system some language to this effect should remain in FAC-14-3. The language should be expanded to reflect that multiples may be identified in the Operations Horizon as well through studies performed in deriving SOLs including those performed for OPA and RTA. Restricting the language to the planning horizon is insufficient as the planning horizon covers a more limited scope of system configurations realized in operations.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	
Document Name	
Comment	
The use of the existing wording from FAC-014-2 “Facilities that are critical to the derivation of the IROL” causes a lot of confusion as to the mean of the word “critical”. The corresponding list of Facilities is referenced by other standards (e.g. CIP-002) with a major impact on compliance to those standards. With lack of clarity and guidelines on the intent regarding the “critical Facilities” that should be included per this requirement. The addition of “stability limits” causes even more confusion, as it is now understood that Facilities impacting SOLs stability limits not considered IROLs should be included on that list. The SDT should rework the purpose and rationale behind those requirements.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
Requirement R5.5 is redundant with TOP-003-3 R1. This is input data necessary to perform OPA and RTA and so the communication of that data is already covered under this requirement. To include it in FAC-014-2 would be redundant and unnecessary.	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	
Comment	
R4 - Developing stability limits should be the responsibility of the TOP, not the RC. TOPs should have greater familiarity with the studies and model details that are used to develop stability limits. The RC should only be involved where there is a discrepancy or question involving multiple TOPs having differing limits.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

Comment 1: The use of the term 'stability limit' in the proposed FAC-014-3 R4, R5.2 and R5.3 is ambiguous. In the definition of 'Reliable Operation' in the NERC glossary of terms, it lists:

"Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits… "

And from Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, page 8:

There are two types of stability limits: (1) Voltage stability limits… (2) Power (angle) stability limits…

Clearly there are multiple meanings of stability limits. CHPD requests the Standard Drafting Team to use additional language to clarify which 'stability limits' are meant here. The definition of Stability Limit, as a capitalized term in the NERC glossary of terms, unfortunately defines the Capitalized term 'Stability Limit' by the lowercase term 'stability limit', so of itself is not very useful as to identifying whether this is a thermal, voltage, or transient / dynamic type of phenomenon.

Comment 2: CHPD would recommend the following language to be used in the proposed FAC-014-3 R5.1. and 5.2 in place of, or in addition to the 'once every twelve calendar months' language. 'or within 30 calendar days (or a later date if specified by the requester)' to be consistent with the construct found in FAC-008-3 R8.2. Given the importance of SOLs (FAC-014-3 R5.1) and IROLs (FAC-014-3 R5.2), utilities may need ratings in a much more operationally appropriate timeframe than 12 calendar months.

Comment 3: In FAC-014-3 R5.5, the RC is required to provide SOLs for its RC area. However, the RC is not actually required to calculate SOLs (only IROLs). Therefore, any SOLs the RC has would be provided by the respective Transmission Operators in the RC area, as specified under FAC-014-3 R3. The Standards Drafting Team may consider revising R5.5. to have Transmission Operators provide SOLs to other Transmission Operators, rather than the RC providing these SOLs.

Comment 4: It would be useful to the PC for FAC-014-3 R5.2 to also include a sub-requirement for the RC to provide the PC with a description of the conditions where the IROL has been observed or was expected to be observed. For example, 'in Winter with heavy south to north transfers', etc. This way, the Planning Coordinator can better test its models to assess whether it can duplicate these conditions in the planning horizon.

Comment 5: The language in FAC-014-3 R6 'Each Reliability Coordinator that is impacted by an IROL…" is unclear by the meaning of 'that is impacted by an IROL'. It is thought that this probably could be removed from the requirement and the function of the requirement would be unaffected.

Comment 6: The requirement for the Transmission Operator to provide SOLs in R3 is likely duplicative to requirements in IRO-010-2, R1. This requirement (IRO-010-2 R1) gives the Reliability Coordinator the authority to request this data. We are already providing these to the RC under IRO-010-2 R3, which requires us to provide this data in accordance with IRO-010-2 R1.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1

Answer	
Document Name	

Comment

OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections:

1. Violation Severity Levels

    i. Requirement 3 VSL

        a. The VSL for Requirement R3 is in disconnect with the language in Requirement R3. The VSL for Requirement R3 references "the periodicity at which the

        RC needs such information" and Requirement R3 simply talks about "in accordance to the Reliability Coordinator's SOL Methodology." Requirement R7 in FAC-011-1 only notes, "The method shall address the periodicity of SOL communication." ReliabilityFirst recommends structuring the VSLs as follows (this is an example of the "lower VSL"):

            1. The Transmission Operator provided its SOLs to its Reliability Coordinator, but was late by less than or equal to 10 calendar days.

    ii. Requirement R6 VSL

        a. The first part of the VSL for Requirement R6 ("The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL") does not match the language of Requirement R6. ReliabilityFirst recommends the beginning of the VSL state:

            1. Reliability Coordinator that is impacted by an IROL did not provide…

Likes 0	
Dislikes 0	

Response

Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay

Answer	
Document Name	

Comment

OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear

understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	
Document Name	
Comment	
The IROLs and SOLs calculated in FAC-014-3 are computed per the RC's SOL Methodology required per R1 in FAC-011-4. The longest time horizon for computing these is an Operational Planning Analysis, which addresses next-day operations. The SDT has not explained why RCs must provide SOLs and IROLs to PCs (R5.1) and other information (see R5.2) and least once every 12 months. Remember, the longest time frame for this information is next-day operations. However, requiring RCs to communicate their SOL Methodology to PCs and TPs per R8.2 in FAC-011-4 has some reliability benefit in that it communicates an operator's tools to planners.	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	
OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	
Document Name	

Comment

In FAC-014-3, R4 as worded, entities that establish stability limits in advance of real-time (as allowed) may not have a mechanism to respond with mitigation plans or active ‘tools’ to respond when the RC communicates a newly emerged limit in near real-time. SRP recommends requiring the RC to guide mitigation when stability limits are changed in near real-time.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

R 5.5 is redundant with TOP-003-3 R1. This is input data necessary to perform OPA and RTA and so the communication of that data is already covered under this requirement. To include it in FAC-014-2 would be redundant and unnecessary. As such, it is recommended that part 5.5 of R5 of FAC-014-2 be deleted.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	
Document Name	

Comment

While we agree with the changes to FAC-014, we will be voting “No” because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
We suggest the intent of Proposed R6 be further clarified. In particular, the meaning of the word 'derivation' is ambiguous. We recommend changing 'derivation' to 'determination' of the limit.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
While we agree with the changes to FAC-014, we are voting "No" because of our Concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	

Answer	
Document Name	
Comment	
Recommend R5.5 be deleted. This is input data needed to perform OPA and RTA per the data specification developed in TOP-003-3 R1.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	
Document Name	

Comment	
The existing SOL/IROL construct and specifically Planning Time Horizon SOLs create duplicative and unessential work. The proposed new construct is a major improvement and aligns the SOL/IROL reliability standards with best practices and the latest revision of TPL-001.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	
Document Name	
Comment	
As noted in our response to Question 7, the revised SOL definition is vital to ensure clear and accurate interpretation of FAC-011 and FAC-014 requirements. Therefore, we recommend that the revised SOL definition be included in the implementation plan for the revised FAC-011 and FAC-014 such that they all have the same effective date.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
The text "in accordance with" is subjective, and could be interpreted inconsistently across RE footprints as well as within RE footprints. For example, would the language from FAC-015-1 "equally limiting or more limiting than" be considered "in accordance with?"	
Likes 0	
Dislikes 0	
Response	

11. FAC-015-1 is predicated on the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative/restrictive/limiting than those found in (or established in accordance with) the RC's SOL Methodology, allowing for justified exceptions. Do you agree with this principle? If not, please explain.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

Assuming that the question should say "equal to or more conservative" rather than just "more conservative" than the Facility Ratings used by the RC/TOP, we agree with the principle, but find the language too confusing and disagree with the implementation.

The phrase in R1 "If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology…" is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true).

In addition, all of the requirements in FAC-015 are related to what limits should be used in planning assessments, therefore the requirements should be included in the TPL standard. Having a separate standard defining the limits that should be used in TPL studies adds unnecessary complication.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

In general, the Facility Ratings established by the Transmission Owner, system steady-state voltage limits and stability criteria should be the same as the RC for facilities located within the Planning Coordinator area with some minor exceptions. The RC's SOL methodology may be less conservative in some cases, for example contingency selection. The RC will be mainly focusing on single contingencies while the PC will focus on single and multiple contingencies. However, the RC's methodology may be less conservative in terms of transmission service (i.e. considers non-firm use). In that case the RC may identify a stability limit whereas the PC did not.

Likes 0	
Dislikes 0	

Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
As stated in the current posted draft of FAC-015-1 R1, it (i.e., Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon) should be ***equal to*** or more conservative/restrictive/limiting.	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
Assuming that the question should say “equal to or more conservative” rather than just “more conservative” than the Facility Ratings used by the RC/TOP, we agree with the principle, but find the language too confusing and disagree with the implementation. The phrase in R1 “If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator’s SOL Methodology…” is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true). In addition, all of the requirements in FAC-015 are related to what limits should be used in planning assessments, therefore the requirements should be included in the TPL standard. Having a separate standard defining the limits that should be used in TPL studies adds unnecessary complication.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
Proposed standard language not in alignment with Comment Form question. The language within Q11 would be correct (with a corresponding "YES" response) if it stated "should be equally or more", which agrees with the actual language within the proposed language FAC-015-1 Requirements R1, R2 & R3. The language contained within this question goes beyond that principle, and would suggest that being equally conservative/restrictive/limiting might require a justified exception.	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Need consistency.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy does not agree with the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative than those found in the RC's SOL Methodology. With this language, the drafting team is implying that it is not appropriate for Planners to plan and Operators to operate from the same or equal ratings without justification. We believe that it can be appropriate for Planning and Operations to use the same/equal ratings, and should not require justification to do so. We recommend the drafting team consider modifying the existing language to reflect that the use of the same/equal rating can be appropriate and not require justification.

Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

Day-to-day operations of the system may require a more conservative/restrictive/limiting Facility Ratings, System steady-state voltage limits, and stability criteria as the system can be operated beyond planning criteria (ex. beyond N-1/-1). Some operating margin is added into facility ratings, system steady state voltage limits, and stability criteria as System Operators are operating the system 24 hours for 365 days in a year which provides the Operators with unique operating challenges – various conditions (outages, generation commitment, contingencies that are beyond planning criteria) – that are beyond what's studied in TPL-001 Planning Assessment. System Operators may have, for example, pre-contingency low/high 'proxy' voltage limits for a particular substation as real time voltage collapse (knee of the curve) calculations are not performed for each operating state. System Operators also have at their disposal Dynamic Feeder Ratings which vary the capability of a feeder; which could be higher of lower than what's assumed in the TPL-001 Planning Assessment.

The definition of System Operating Limit states: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria." FAC-015 would introduce operating criteria for multitude of operating system configurations into TPL-001 Planning Assessment.

Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6

Answer	No
Document Name	
Comment	

The question as worded states the limits should be more conservative, which Entergy does not agree with, the limit should be equally or more limiting. We believe this was just an oversight in the wording of the question since the proposed standard uses the word “equally”.

Likes 0	
Dislikes 0	
Response	

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1

Answer	No
Document Name	
Comment	

Please refer to the comments submitted by the SPP Standards Review Group.

Likes 0	
Dislikes 0	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	
Comment	

Comment 1: Facility Ratings should be provided by the Transmission Owner and Generation Owner to both the Planning Coordinator and Reliability Coordinator. Facility Ratings are what they are – from our experience, the trouble comes in with assumptions about ambient conditions.

In CHPD’s experience, the greatest challenge between planning and operations is that we utilize dynamic ambient-temperature based ratings. In real-time, there is a very wide band of potential transmission line ratings based on the ambient temperature, just as there are a wide range of ambient temperature conditions throughout the day. Therefore, in real-time operations we use many ratings throughout the day.

In long term system planning and operations planning, it is clearly inappropriate to run all the studies through all ratings sets. Our practice is to use what we as a utility have felt is appropriate for the expected ambient conditions, in coordination with our neighbors.

Similarly, while it is recognized that there are differences between the planning and operational voltage criteria, CHPD has not experienced great difficulty in operating its system, even with the different planning and operational criteria.

CHPD feels that there isn't a need to create prescriptive requirements in order to accomplish this reliability objective. It is the Planning Coordinator's responsibility to adequately plan the system for growth, capacity, and integration of service in the Planning Horizon; it is the Reliability Coordinator's responsibility to plan and operate the system in the Operations Horizon. Given these different responsibilities, we feel it is not appropriate for one entity to determine another entity's criteria since each performs a different system function in a different system timeframe. **Comment 2:** The term 'System Operating Limit (SOL)' from FAC-014-2 has now been replaced with 'Facility Ratings' in FAC-015-1. While System Operating Limits (SOLs) are the result of *studies* assessing the performance of Facility ratings and performance criteria against expected system conditions and events, Facility Ratings are ***not*** the result of studies and assessments – they 'are what they are'. Furthermore, under FAC-008, the Transmission Owner and Generator Owner is already required (under FAC-008 R6-R8) to make its Facility Ratings available to the Reliability Coordinator and Planning Coordinator. Under FAC-015-1 R4, the Planning Coordinator is now being required to provide Facility Ratings. While this was in the spirit of what was previously in FAC-014-2 with 'SOL' replaced with 'Facility Ratings', this change is now requiring the Planning Coordinator to provide something that is the responsibility of the Transmission Owner under FAC-008 to provide. CHPD recommends removal of this requirement because its objective is carried in FAC-008.

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	No
Document Name	

Comment

As stated in proposed Reliability Standard FAC-015-1 R1, Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be **equal to or more conservative/restrictive/limiting**…

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees in principle, but as mentioned above, there should be a feedback loop. More information about how to coordinate the planning horizon events with the operations horizon events would be useful, and a table describing the various time horizons, contingencies, and allowable actions, such as Table 1 of TPL-001-4, may help add clarity.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

ITC agrees with the general concept that more or at least as conservative SOL's should be utilized in the Planning Assessments as those considered in real time operations. The SDT should clarify how exceptions would be justified and who would have the authority to justify them. There will be instances where lower Facility Ratings will be identified in real time as Facility Ratings are continually reviewed by TO's. This will create situations when more limiting SOL's may be used in real time operations that those that were used in the latest or even current Planning Assessments. There will also be projects considered in future Planning models that may increase Facility Ratings or other SOL's. It should be made clear that this would be acceptable.

The standard should only specify the end objective and not the process to achieve that objective. Each system has a defined Planning Criteria that is published and readily available to the RC. This Criteria has defined voltage limits and stability criteria that have been identified that work with the Facility Ratings for that system. By utilizing an RC based methodology, you will be forced to go to either a least common denominator criteria or not be able to take in to account specific issues inherent in a system. Having to justify each exception for every rating change due to a project, rating correction, use of seasonal ratings in operations is not prudent for either the PC or the TP.

ITC does not believe FAC-015-1 is necessary to achieve the required outcome. Simple modifications to TPL-001-4 may allow for the same desired outcome.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

We agree with the concept that system performance criteria used in the Planning Assessments should be more restrictive or at least line up with system performance criteria used in the Operating Horizon. But, system performance criteria used in the Operating Horizon cannot be more restrictive than those used in the Planning Horizon. The proposed standard, as written, allows the RC to establish criteria without consultation with the TP and the PC. In our opinion, this is a recipe for failure.

Furthermore, we see nothing in the NERC Functional Model that would allow the PC and RC to develop or establish system performance criteria as part of their defined roles, or to establish performance criteria that could be more restrictive than the criteria provided by the Transmission Owners and Transmission Planners. Standard TPL-001-4 dictates system performance requirements. PC and RC cannot arbitrarily decide to come up with new, more restrictive system performance criteria.

We are also concerned that requirements R1 through R3 allow for no input from the Transmission Planners regarding the development of any performance criteria established by the Planning Coordinator. Requirement R4 then requires the PC to simply hand-down its criteria to the Transmission Planner without any input as to whether the criteria are reasonable or whether meeting the criteria is feasible. At a minimum, requirements R1 through R3 need to recognize that the development of any PC based system performance criteria has to be a collaborative effort between the PC and the TPs and the Transmission Owners. Any tightening of performance criteria will likely require capital investment and we need to hear from the Planning Coordinators as to why the planned system needs to meet the new, more stringent reliability requirements.

Requirements R1 through R3 require the Planning Coordinator to provide a technical justification to the Reliability Coordinator for using less limiting ratings, voltage limits, or performance criteria. We can see that some equipment ratings can change from year to year, and perhaps the corrective action plans should also be provided for those parts of the system that have been or are planned to be upgraded. However, we disagree with the approach proposed by the SDT for the voltage limits and stability criteria, and instead believe that the drafting team needs to have the Reliability Coordinator provide a technical basis to the Planning Coordinator and the Transmission Planners regarding why more limiting ratings and performance criteria should be required in planning assessments. As any tightening of ratings and performance criteria will likely require capital investments, we need to hear from the Reliability Coordinators as to why the system as provided/planned needs to meet the new, more stringent reliability requirements.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group would like the drafting team to provide some clarity on the short term derates pertaining to the Planning Horizon. Also, we would ask the drafting team to provide clarity on what are justified exceptions or how the term is defined.

Likes 0	
Dislikes 0	

Response

James Grimshaw - CPS Energy - 3

Answer	No
Document Name	

Comment

Planning Assessments for the Near-Term Transmission Planning Horizon utilize base case models built meeting requirements in MOD-032. These base case models incorporate future additions and upgrade projects that may be put in place to resolve existing SOLs. Assessing the continuing need for Corrective Action Plans, as required by TPL-001, would address the need to study the existing SOLs, however, to properly evaluate other future projects, assumptions must be made that existing Corrective Action Plans will be implemented. This means, for example, that studies performed for year 5 should assume that Corrective Action Plans identified for Year 2 have already been implemented, which means an existing SOL may have already been upgraded when studying Year 5.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

PNMR believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA. Instead of allowing for exceptions, PNMR suggests that the RC, TOP, and PA should jointly develop system performance criteria.

PNMR suggests that R1 be revised to provide clarity on what is less conservative/restrictive/limiting. Is it the intention of the SDT that the Planning Coordinator would have to provide a technical justification to the RC for using less limiting Facility ratings based on a Corrective Action Plan? For example, Facility A has a rating of 100 MVA. A previous Planning Assessment identified an overload of Facility A. To mitigate the overload the Corrective Action Plan is to increase the rating of Facility A to 200 MVA. TPL-001-4 R1.1.3 requires the Planning Coordinator to include this planned change to the existing Facility in the System model used for the Planning Assessment. Does this situation result in the Planning Coordinator using a less limiting Facility Rating than established in accordance with the RC's SOL Methodology? PNMR strongly believes that the Planning Coordinators should not have to provide technical justification to their RC for simply following the TPL-001 standard.

Likes 0	
Dislikes 0	

Response

Gladys DeLaO - CPS Energy - 1

Answer	No
Document Name	

Comment

Planning Assessments for the Near-Term Transmission Planning Horizon utilize base case models built meeting requirements in MOD-032. These base case models incorporate future additions and upgrade projects that may be put in place to resolve existing SOLs. Assessing the continuing need for Corrective Action Plans, as required by TPL-001, would address the need to study the existing SOLs, however, to properly evaluate other future projects, assumptions must be made that existing Corrective Action Plans will be implemented. This means, for example, that studies performed for year 5 should assume that Corrective Action Plans identified for Year 2 have already been implemented, which means an existing SOL may have already been upgraded when studying Year 5.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

The proposed Standard places the onus on the PC to provide the criteria to be used by the Transmission Planner in completing Planning Assessments. In SPP, the SOLs have historically been defined as permanent and temporary flowgate ratings and operating guides. Based on that methodology, it is difficult, if not possible, for planners to identify all situations that potentially may cause an operating guide that would lower a rating; and, as such, the planner may not study each SOL in their Planning Assessment.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

As previously posed in our response to Question 10, would the language from FAC-015-1 “equally limiting or more limiting than” be considered “in accordance with” as provided in FAC-014-3?

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment	
While we agree with the principle, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements to existing standards or modifying existing standards. Planning assessments modeling data including facility ratings are based on MOD-032-1 data requirement. If it is desired to coordinate modeling data with RC SOL methodology, RC SOL methodology should align with the MOD-032-1 requirement instead of drafting a new requirement.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the principal but does not agree that there is a need for R1, R2 and R3 as they provide minimal additional reliability benefits and create an unnecessary additional burden for the Planning Coordinator.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCE supports this principle and believes that best planning practices include more restrictive or equal limits compared to operational limits to provide our transmission operators with the necessary grid assets or advanced knowledge of system limitations to reliably operate the transmission system.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	

SRP agrees with the principle, but has a concern with the wording of R1.

-R1 refers to Facility Ratings as being established in accordance with the Reliability Coordinator's SOL Methodology, though Facility Ratings are established by a TO or GO in accordance with their FAC-008-3 Facility Ratings methodology. Perhaps the requirement should read "…the Facility Ratings used to establish SOLs in accordance with the RC's SOL Methodology..."

Likes 0	
Dislikes 0	
Response	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	
Comment	

The SDT is definitely on target with its assessment that the system must be planned to at least as conservative limits as are used in the operation of the system in real-time. Because planning analyses cannot cover all operating conditions to do any different would be to plan a system that could not be operated within acceptable limits.

Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	
Comment	

Peak agrees with this principle.

Likes 0	
Dislikes 0	
Response	

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment

- We agree with the principle, but we disagree with the implementation.
- We agree with the following comment from Seattle City Light:
    - *The phrase in R1 "If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology…" is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true).*
    - Proposed alternative language for R1: In planning assessments and operations, facility continuous ratings shall be used for the pre-contingency state and facility ____ hour/minute ratings shall be used for the post-contingency state.
    - As stated in the purpose section of FAC 008 a Facility Rating is essential for the determination of System Operating Limits. We disagree with the notion that Facility Ratings are SOLs. While Facility ratings are based on characteristics of the Facility in accordance with FAC 008, SOLs are system limits developed using steady state and stability simulations based on a defined set of performance criteria such as those defined in the currently effective FAC-010 and FAC-011 standards.
    - The required coordination between planning and operations can better be addressed by the regional reliability organization like WECC which has an open and established process for developing regional criteria. Reliability coordinators' SOL methodologies are developed without input from planning coordinators.
    - Given the objective is to ensure coordination between planning and operations, the RC must be assigned a responsibility in the standard. For example, if the standard entails comparing planning models with operations models, then the RC must have the responsibility to provide the operations models and the obligation to timely respond to questions the PC may have in the course of the comparison in order to resolve any discrepancy in facility ratings, etc.
    - Requirement R1 of TPL 001-4 requires the planning coordinator to use modelling data provided in accordance with MOD 10 and MOD 12 (which are now replaced with MOD 32). As such using modelling information such as facility ratings obtained from the reliability

coordinator's SOL methodology can be inconsistent with TPL 001-4.

- The ratings and limits used in planning do not have to be more conservative than those used in operations. Equally conservative ratings and limits can be sufficient. For example, a 0.9 p.u. low voltage limit can applicable in both planning and operations.
- CAISO PC proposes Requirements R1 to R5 be replaced with something like:
  - Planning Coordinators(PCs), Transmission Planners (TPs), Reliability Coordinators (RCs) and Transmission Operators (TOPs) within a Regional Reliability Organization (RRO) area shall collaborate in developing and implementing consistent applicable Facility Ratings duration criteria, System steady-state voltage limits, and stability criteria for use in planning assessments and operations.
-

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	Yes
Document Name	

Comment

However it is not clear on how to handle situations when the planning assessment was performed with the equal or more conservative limit and actual conditions change resulting in more restrictive limits in the Operating Horizon.

Note: ERCOT does not support this response

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT reads the standard to say that the values used in Planning Assessments could be *equal or* more limiting than those used in the RC's SOL Methodology, and not that they must be more limiting, as suggested by the question.

Likes 0	
Dislikes 0	

Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

12. Do you agree that coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria as required in Requirements R1-R3 should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1	
Answer	No
Document Name	
Comment	
Coordination for SOLs should be incorporated into base planning models required by MOD-032, the same as Facility Ratings are incorporated into these base models (as required by MOD-032). TPL-001 requirements would then stay the same, as these studies should be based upon models built as required by MOD-032. FAC-015 Requirement R1 may be more appropriately incorporated into the FAC-008 facility rating as part of the MLSE calculation for individual facilities. For groups of facilities, identification of a limiting flow-gate may be more appropriate. If this is not feasible, then the requirement should be incorporated into the modeling requirements of MOD-032.	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that this language continues to create a gap between planning and operations. PNMR proposes the removal of the phrase “of the Near-Term Transmission Planning Horizon”. Long-Term planning should be performed to the same or more stringent Facility Ratings, System steady	

state voltage limits, and stability performance criteria.	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	No
Document Name	
Comment	
Coordination for SOLs should be incorporated into base planning models required by MOD-032, the same as Facility Ratings are incorporated into these base models (as required by MOD-032). TPL-001 requirements would then stay the same, as these studies should be based upon models built as required by MOD-032. FAC-015 Requirement R1 may be more appropriately incorporated into the FAC-008 facility rating as part of the MLSE calculation for individual facilities. For groups of facilities, identification of a limiting flow-gate may be more appropriate. If this is not feasible, then the requirement should be incorporated into the modeling requirements of MOD-032.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
If premise is to ensure consistency with TPL-001-4, then language within Standard should reference, "...annual Planning Assessment.." versus just the near-term horizon	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	No
Document Name	
Comment	

We expect the FR and limits used in the TPL assessments to be very similar if not identical in most cases between the near-term and long-term horizons. Since most major transmission projects are identified in the long-term horizon and take several years to be completed, it would make no sense for the PC/TP to use less limiting criteria for the long-term horizon than the near-term horizon or the RC's SOL Methodology. We suggest removing the reference to Near-term horizon and simply referring to the Planning Assessment as in R4.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group has a concern pertaining to the performance of meeting Requirements R1 and R2. They should be limited to the near term BES representation of year one and two in the near term planning horizon power flow cases set. The BES representations will differ between the Operations and Planning power flow cases due to the proposed project to meet Planning Assessment needs for the year 5 through 10 models.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The same concepts that apply to the Near-Term Transmission Planning Horizon should apply to the Long-Term Planning Horizon. ITC agrees with the general concept that more or at least as conservative SOL's should be utilized in the Planning Assessments as those considered in real time operations. The SDT should clarify how exceptions would be justified and who would have the authority to justify them. There will be instances where lower Facility Ratings will be identified in real time as Facility Ratings are continually reviewed by TO's. This will create situations when more limiting SOL's may be used in real time operations that those that were used in the latest or even current Planning Assessments. There will also be projects considered in future Planning models that may increase Facility Ratings or other SOL's. It should be made clear that this would be acceptable. *Per FAC-008-3, Facility Ratings are calculated by the TO and communicated to the TP and TOP (typically all within the same organization) and to the PC and RC. These ratings are used throughout both the Near-Term and Long-Term Planning Assessments unless a planned project causes them to change or a project that is under construction goes in service. Coordination occurs today and should be allowed to continue without strict dictates on exactly how each organization will perform their work. The standard should only specify the end objective and not the process to achieve that objective.*	
Likes 0	

Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

We question what the value of R1-R3 is and if the requirements are even needed. R1-R3 are really dealing with TPL-001-4 and there shouldn't be three additional requirements in FAC-015-1 to deal with the uncommon occurrence of a PC using less limiting Facility Ratings, System steady-state voltage limits, or stability performance criteria. It certainly shouldn't require a technical justification, it should only require coordination

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

The TPL-001-4 study requires MOD data to be used in TPL-001-4 R1. This includes the rating of transformers and transmission lines. Voltage limits (including the stability performance of the voltage) is addressed in TPL-001-4 R6 and are the required criteria for the Planning Assessment. These requirements are applicable to both the Near-Term Transmission Planning Horizon and the Long-Term Planning Horizon. Specifying the time horizon in FAC-015-1 should not be done because it does not modify the time frame requirement found in TPL-001-4 for when these thermal and voltage limits should be used. CHPD feels this language should be removed from FAC-015-1 R1-R3.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1

Answer	No
Document Name	

Comment

Please refer to the comments submitted by the SPP Standards Review Group.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	No
Document Name	

Comment

NERC TPL-001 Planning Assessment should have Facility Ratings, System steady state voltage limits, and stability performance criteria established for both Near-Term and Long-Term Transmission Planning Horizon, however these should be defined separately from RC's SOL Methodology.

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

Desire consistency.

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	No
Document Name	

Comment

Peak believes that requirements R1 through R3 should also apply to other NERC required assessments such as the Transfer Capability assessments required by FAC-013-2. It is important for reliability that these Transfer Capability assessments abide by the same principles as the Planning

Assessments for the Near-Term Transmission Planning Horizon. Otherwise the Transfer Capability assessments could use a different set of Facility Ratings, System Voltage Limits, and stability criteria than those established in accordance with the RC's SOL Methodology, which propagates the problems that are being addressed by FAC-015-1 Requirements R1 through R3.

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

See the response to Q16.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NSRF believes there is insufficient technical reason to exclude the Long-Term Transmission Planning Horizon from Requirements R1-R3. The use of different Facility Ratings, System steady state voltage limits, and stability performance criteria between the Near-Term and Long-Term Transmission Planning Horizons has the potential to be problematic. To ensure consistency with Reliability Standard TPL-001-4, which includes both the Near-Term and Long-Term Planning Horizons in the Planning Assessment, recommend the following change to R1-R3:

Each Planning Coordinator… used in its annual Planning Assessment are equally limiting…

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	No
Document Name	

Comment	
We do not see any reason why the method used to establish Ratings/Limits would be different in the near-term and longer-term horizons. The time horizon necessary to fund, plan and construct facilities is much longer than 1 to 2 years. Unacceptable system performance needs to be identified five to ten years in the future to allow for building facilities to solve these issues. As for alternative language, we would just strike the words "of the Near-Term Transmission Planning Horizon" from the requirements.	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES believes there is insufficient technical reason to exclude the Long-Term Transmission Planning Horizon from Requirements R1-R3. The use of different Facility Ratings, System steady state voltage limits, and stability performance criteria between the Near-Term and Long-Term Transmission Planning Horizons has the potential to be problematic. To ensure consistency with Reliability Standard TPL-001-4, which includes both the Near-Term and Long-Term Planning Horizons in the Planning Assessment, LES recommends the following change to R1-R3: "Each Planning Coordinator… used in its **annual** Planning Assessment are equally limiting…".	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We don't see any reason why the method used to establish Ratings/Limits would be different in the near-term and longer-term horizons. The time horizon necessary to fund, plan and construct facilities is much longer than 1 to 2 years. Unacceptable system performance needs to be identified five to ten years in the future to allow for building facilities to solve these issues. As for alternative language, we would just strike the words "of the Near-Term Transmission Planning Horizon" from the requirements.	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
We are confused by the question as posed. The proposed revisions provide a planning horizon of Long-term Planning for R1 through R3.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
We think that It is unnecessary and less worthwhile to include the Long-Term Planning Horizon (6 - 10 years in the future) because the future system assumptions (load, generation, transfers, etc.) are more uncertain and speculative than the Near-Term Planning Horizon. So, the results would be less useful and subject to change than the Near-Term Planning Horizon results.	
Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agreed with the SDT that Planning Assessments in scope for these requirements should be limited to the Near-Term Transmission Planning Horizon. PCs are already required to share their results with their RCs, per NERC Reliability Standards IRO-017-1. Sharing similar results from Planning Assessments that are analyzed over a longer time period may not readily benefit the RC looking to develop Operating Plans that alleviate SOL Exceedances.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We concur with that statement as this is the closest Planning time horizon to that of Operations.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
With the exception of planned facility upgrades, we are unaware of why facility ratings, steady-state voltage limits, and stability performance criteria would be different in the Long-Term vs. Near-Term Planning Horizons and would need to be coordinated with the Reliability Coordinator. Therefore, for the Eastern Interconnection, limiting the coordination from the Near-Term Planning Horizon with the Operating Horizon to a discussion of changed facility ratings should be adequate to maintain reliability.	
Likes 0	

Dislikes 0	

Response

Julie Hall - Entergy - 6

Answer	Yes
Document Name	

Comment

Entergy agrees with the rationale that the time period of 1 to 5 years the assumptions tend to be more certain.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy agrees that the Planning Assessments should be limited those for the Near-Term Transmission Planning Horizon, as it is very difficult to make an assessment on stability in years 6-10. We agree that this should only apply to the Near-Term Planning Horizon.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Once these facilities move into the Near-Term horizon, 5 years provides sufficient time to identify thermal constraints in the same manner as they would be seen operationally and develop appropriate Corrective Actions. The Near Term horizon is more than enough time to identify constraints and prepare any needed operational strategies for scenarios that may be candidates to be declared an IROL by the RC.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Limiting to the Near-Term assessment is fine. However, the Manitoba Hydro Planning Coordinator does not typically change the limits/criteria/ratings between the Near-Term and Long Term horizons. The exception would be Facility Ratings where a modification occurred (Corrective Action Plan installed) or possibly a facility rating methodology changed.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The Facility Ratings, voltage limits, and stability criteria (SOLs) should be limited to Near-Term Transmission Planning Horizon. The system conditions and uncertainty beyond Near-Term Transmission Planning Horizon are better suited for large capital projects which require extensive licensing. Unnecessary engineering and licensing may occur if more restrictive SOLs are required for Long Term Transmission Planning.	

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

AZPS agrees that it should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon and further recommends that it should be limited to only studies for years 1 to 2. The Near-Term transmission planning horizon covers years 1 to 5 and is much longer than the operating horizon. Requiring SOL methodology limitations to be used for years 1 – 5 of the Near-Term Planning Horizon could be problematic and is unnecessary.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

While we agree with the principle since the near term planning horizon is more aligned with operations horizon, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements in existing standards or modifying existing standards. R1 is covered in MOD-032-1. R2 and R3 are already addressed in TPL-001-04.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

We disagree with the implementation of FAC 15-1. The Facility Ratings, System steady state voltage limits, and stability performance criteria used in the near term are not different from those used in the long term.

Likes 0	
Dislikes 0	

Response

13. In Requirements R1 – R3, the SDT is proposing to allow a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology. Do you agree that this provides adequate flexibility (in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized; e.g., up-rating a line in a future project) without compromising reliability? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

: It makes sense to require PC/TPs to use the same "type" of Facility Ratings and Voltage Limits as the RC/TOP (i.e. if the TOP is operating to 20-minute emergency ratings, the TP/PC shouldn't be planning to 60-minute emergency ratings). If that is the intent, then this requirement should be be included in the TPL-001 standard rather than in this separate FAC-015 standard. The language I would put in the TPL standard would look something like: "Each Transmission Planner and Planning Coordinator shall use the same or a more conservative category of Facility Rating (i.e. using the same emergency rating duration, or using only normal ratings) as used by the TOP/RC in operations."

The language of the proposed requirements implies that the RC will be the arbiter of which planned projects can be included in planning cases, which does not make sense. If the intent is make sure the RC is aware of these planned projects, the language should be changed (perhaps in a separate

requirement) to something like: "the PC/TP shall inform its associated RC of any planned projects that result in changes to Facility Ratings, System Voltage Limits or Stability Limits used in the planning horizon." If the drafting team sees a need to set the terms under which a project can be included in a TPL planning case, that should be included in the TPL-001 standard, not decided on a case-by-case basis by the RC.

In the case of Stability Criteria, TPL-001-4 and WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

R1: The Facility Ratings are coordinated through the MOD-032-1 model development process. Modeling differences from year to year are documented but not between each series of models. The RC is regularly updating Facility Ratings to perform operational and real time studies. The Planning Models are made annually with assumptions made on in-service dates. A particular RC model could easily be out-of-sync with a particular PC model on certain pieces of equipment, however there should be no reliability gap as a result. If the Facility Ratings used by the RC are different from the Year 1 planning model, perhaps the RC should provide a technical justification to the PC instead? This seems to be a lot of work for minimal if any reliability gain.

R2: The PC has documented steady state voltage criteria as required by TPL-001-4 R5. The Transmission Operator fundamentally sets the steady state voltage limits on each BES bus as per NERC NERC FAC-014-3 R2 and NERC FAC-011-4 R3.1. It makes more sense for the PC to coordinate with the

Transmission Operator(s) within the PC area to ensure that limits/criteria are coordinated and exceptions noted. This would be an easy task that it is already performed in Manitoba. The PC criteria is documented in the Transmission System Interconnection Requirements document (created to be compliant with FAC-001) and exceptions developed by the Transmission Operator are noted in a referenced Normal Operating Procedure.

R3: The PC has documented steady stability criteria as required by TPL-001-4 R4 and R5. The The Transmission Operator sets the stability criteria as per NERC FAC-014-3 R2 and NERC FAC-011-4 R4.1. It makes more sense for the PC to coordinate with the Transmission Operator(s) within the PC area to ensure that limits/criteria are coordinated and exceptions noted. This would be an easy task that it is already performed in Manitoba. The PC criteria is documented in the Transmission System Interconnection Requirements document (created to be compliant with FAC-001).

Manitoba Recommends removing R1 and having the coordination in R2 and R3 occur between the PC and relevant Transmission Operator(s) that are responsible for the PC area if needed. Alternatively, the criteria developed by the PC under TPL-001 could be shared with the Transmission Operator.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Suggest adding the phrase “at the same assumed ambient temperature(s)” after the term “Near-Term Transmission Horizon” in the first sentence of R1. The purpose is to make clear that the use of dynamic ratings based on ambient conditions in Operations for thermal ratings can be utilized and that the correlation of the Planning Coordinators Facility Ratings and the Facility Ratings associated with the Reliability Coordinator can be at a discrete small set of ambient temperatures.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	No
Document Name	

Comment

It makes sense to require PC/TPs to use the same “type” of Facility Ratings and Voltage Limits as the RC/TOP (i.e. if the TOP is operating to 20-minute emergency ratings, the TP/PC shouldn’t be planning to 60-minute emergency ratings). If that is the intent, then this requirement should be be included in the TPL-001 standard rather than in this separate FAC-015 standard. The language I would put in the TPL standard would look something like: “Each Transmission Planner and Planning Coordinator shall use the same or a more conservative category of Facility Rating (i.e. using the same emergency rating duration, or using only normal ratings) as used by the TOP/RC in operations.”

The language of the proposed requirements implies that the RC will be the arbiter of which planned projects can be included in planning cases, which does not make sense. If the intent is make sure the RC is aware of these planned projects, the language should be changed (perhaps in a separate requirement) to something like: “the PC/TP shall inform its associated RC of any planned projects that result in changes to Facility Ratings, System Voltage Limits or Stability Limits used in the planning horizon.” If the drafting team sees a need to set the terms under which a project can be included in a TPL planning case, that should be included in the TPL-001 standard, not decided on a case-by-case basis by the RC. In the case of Stability Criteria, TPL-001-4 and WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria.	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Although the NSRF agrees there may be cases where this flexibility is necessary, there is no criterion to determine what acceptable technical justification is. Nor does the standard identify who it is that determines that the technical justification is acceptable. This leaves ambiguity in the proposed requirements. The requirements need to clearly spell out which entity is responsible for determining when it is appropriate for less limiting criteria to be used in planning evaluations. As it is the real-time operators who will have to operate the system as designed, we believe the RC should have the final say as to whether the justification is appropriate or not.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	

Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
For consistency.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
R1-R3 should provide Transmission Planner and not only Planning Coordinator the opportunity to provide a technical justification for ‘different’ Facility Ratings, System steady state voltage limits, and stability performance criteria to its Reliability Coordinator. The alternative language should have an addition of “Transmission Planner or” as follows: “[…]If the **Transmission Planner or** Planning Coordinator uses less limiting System steady -state v established in accordance with its Reliability Coordinator’s SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.”	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Please refer to the comments submitted by the SPP Standards Review Group.	

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

While CHPD appreciates the nod to flexibility by allowing the Planning Coordinator to use different criteria, with justification to the Reliability Coordinator, CHPD disagrees with the statement that this will be a rare circumstance. As stated above, CHPD feels a better tool would be for the Reliability Coordinator and Planning Coordinator to exchange methodologies and ratings assumptions / practices, and to have the ability to comment to each other with technical concerns. Alternative language for R1-R3 could be something to the effect:

R1. The Reliability Coordinator shall provide its methodology, performance criteria, and ratings assumptions to each Planning Coordinator in the Reliability Coordinator's area

1. Each Calendar Year
2. 90 days prior to a change

R2. The Planning Coordinator shall provide its methodology, performance criteria, and ratings assumptions to each Reliability Coordinator in the Planning Coordinator's area

1. Each Calendar Year
2. 90 days prior to a change

R3. If the (Planning Coordinator or Reliability Coordinator) receive technical comments in writing from the (Reliability Coordinator or Planning Coordinator), the (Planning Coordinator or Reliability Coordinator) shall respond to those comments within 30 days.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

Please see our comments for question number 6 regarding feedback loops.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

This would place too much burden on both the PC and TP. Per FAC-008-3, Facility Ratings are calculated by the TO and communicated to the TP and TOP (typically all within the same organization) and to the PC and RC. These same ratings are used throughout both the Near-Term and Long-Term Planning Assessments unless a planned project causes them to change or a project that is under construction goes in service. Coordination occurs today and should be allowed to continue without strict dictates on exactly how each organization will perform their work. The standard should only specify the end objective and not the process to achieve that objective.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

With the exception of planned facility upgrades, we are unaware of why any technical justification would be required by the PC to the RC. Conversely to what is stated in the question, we do not believe that facility upgrades are rare circumstances and compromise reliability.

Furthermore, we see nothing in the NERC Functional Model that would allow the PC and RC to develop or establish system performance criteria as part of their defined roles, or to establish performance criteria that could be more restrictive than the criteria provided by the Transmission Owners and Transmission Planners. Standard TPL-001-4 dictates system performance requirements. PC and RC cannot arbitrarily decide to come up with new, more restrictive system performance criteria.

We are also concerned that requirements R1 through R3 allow for no input from the Transmission Planners regarding the development of any performance criteria established by the Planning Coordinator. Requirement R4 then requires the PC to simply hand-down its criteria to the Transmission Planner without any input as to whether the criteria are reasonable or whether meeting the criteria is feasible. At a minimum, requirements R1 through R3 need to recognize that the development of any PC based system performance criteria has to be a collaborative effort between the PC and the TPs and the Transmission Owners. Any tightening of performance criteria will likely require capital investment and we need to hear from the Planning Coordinators as to why the planned system needs to meet the new, more stringent reliability requirements.

Requirements R1 through R3 require the Planning Coordinator to provide a technical justification to the Reliability Coordinator for using less limiting ratings, voltage limits, or performance criteria. We can see that some equipment ratings can change from year to year, and perhaps the corrective action plans should also be provided for those parts of the system that have been or are planned to be upgraded. However, we disagree with the approach proposed by the SDT for the voltage limits and stability criteria, and instead believe that the drafting team needs to have the Reliability Coordinator provide a technical basis to the Planning Coordinator and the Transmission Planners regarding why more limiting ratings and performance criteria should be required in planning assessments. As any tightening of ratings and performance criteria will likely require capital investments, we need to hear from the Reliability Coordinators as to why the system as provided/planned needs to meet the new, more stringent reliability requirements.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No
Document Name	

Comment

- For the reasons noted in the response to Question 11, the ISO does not agree with the implementation of FAC-015. However, if it is implemented, we support allowing a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology.
- We request the term "Facility Ratings" in the requirement and throughout the standard be replaced with something like "applicable Facility Ratings duration criteria".
- "In the case of Stability Criteria, TPL-001-4 and TPL-001-WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria."

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

There needs to be language defining who decides that the technical justificaiton is acceptable.

Likes 0	
Dislikes 0	

Response
Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment
We agree with the statement in principal but the Facility Rating provided by the equipment owner that is applicable for the year of the study (which may be less restrictive) should still be the one that is used. The language in the requirement should address this.

Likes 0	
Dislikes 0	

Response
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment
PNMR believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA. Instead of allowing for exceptions, PNMR suggests that the RC, TOP, and PA should jointly develop system performance criteria.

Likes 0	
Dislikes 0	

Response
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment	
In most situations, proposed R1-R3 provides adequate flexibility without compromising reliability; however, it raises a question: If the RC needs to lower an SOL below the Facility Rating in real-time due to clearance issues, how does the PC monitor SOLs to determine if an SOL has gone lower than the Facility Rating, necessitating technical justification?	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
In the event planned transmission system upgrades exist, the PC would often need to use less limiting Facility Ratings for those facilities. The SDT should consider including a firm exclusion of transmission system upgrades for FAC-015-1 R1 to avoid unnecessary documentation for a frequent and commonly understood justification. ERCOT suggests the following revision to achieve this purpose: Each Planning Coordinator, when developing its steady -state modeling data requirement to ensure that, ***for all Facilities other than those with planned transmission upgrades***, Facility Ratings used in its Planning Assessment of the Near -Term Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. ****Please refer to the attached comment form for redlined language.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

PCs are already required to provide the results of their Planning Assessments to impacted RCs, per NERC Reliability Standards IRO-017-1. The inclusion of technical justifications for using less limiting SOLs would then be included in addition to these results. We caution the SDT that the target audience of a RC's SOL Methodology are TOPs, not PCs. TOPs use this methodology to determine applicable owner -provid System Voltage Limits, and stability limits that can be used in operations. We feel this creates a process gap that should be addressed by requiring the RC to include, in its SOL Methodology, a method for PCs to determine applicable owner ltage Limits in their Planning Assessments.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

While we agree with the principle, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements to existing standards or modifying existing standards. MOD-032-1 and TPL-001-4 should be modified to address.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The proposed process for exceptions is adequate because it ensures visibility of these exceptions to the Reliability Coordinator. The transmission system is nuanced and providing this flexibility is important granted that the affected parties are involved (such as the RC).

Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes

Document Name	
Comment	

Reclamation supports the use of less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in the RC's SOL Methodology when appropriate.

Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	
Comment	

There may be circumstances where there is a technically justifiable reason for using less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in accordance with (or described in) the RC's SOL Methodology. However, if the RC does not agree with the technical justification provided by the PC, the RC should have the authority to refute the justification which would then require that the stipulations in the RC's SOL Methodology would prevail.

Likes 0	
Dislikes 0	
Response	

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	
Comment	

Supporting NPCC comments

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Duke Energy agrees that the proposal provides adequate flexibility, however, we request further clarification from the drafting team on how question 11 above, works in concert with question 13.

Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6

Answer	Yes
Document Name	
Comment	

Entergy agrees with allowing the PC to provide a technical justification. Not all situations can be covered and there may be extenuating circumstances where it is necessary to use less limiting ratings.

Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	Yes
Document Name	
Comment	

AECI agrees that this approach provides adequate flexibility. A Registered Entity may encounter circumstances where there is a technically justifiable reason for using less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in the Reliability Coordinator's SOL Methodology.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed

Answer	Yes
Document Name	
Comment	

A sound technical justification may indeed be appropriate in certain cases and this flexibility is well captured by the standard.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	Yes
Document Name	
Comment	

However, the SDT should include the Transmission Planner as an entity that can also provide lower facility ratings and limits as they are required under TPL to establish those limits for facilities in their purview.

Note: ERCOT does not support this response.

Likes 0	
Dislikes 0	

Response

James Grimshaw - CPS Energy - 3

Answer	Yes
Document Name	
Comment	

Reference MOD-032-1, attachment 1, "items marked with asterisk indicate data that vary with system operating state or conditions." In this case, the new “system operating state” is the particular future year under study which should incorporate all anticipated topology and rating changes for that year. These topology and rating changes may have been added to upgrade an existing SOL.

Likes 0	
Dislikes 0	

Response

Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Reference MOD-032-1, attachment 1, "items marked with asterisk indicate data that vary with system operating state or conditions." In this case, the new "system operating state" is the particular future year under study which should incorporate all anticipated topology and rating changes for that year. These topology and rating changes may have been added to upgrade an existing SOL.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
We think that although the circumstances for more limiting SOLs may be rare, it is wise to include provisions for addressing them in case they would occur.	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

14. Do you agree that the information identified in Requirement R6 is necessary for each impacted RC and TOP to properly evaluate instability, Cascading, or uncontrolled separation identified in planning assessments for use in establishing stability limits and IROLs in the operations horizon? If not, please explain and provide alternative language.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
We disagree that Near-Term Transmission Planning Horizon and Transfer Capability Assessments will necessarily be useful for establishing stability limits and IROLs in the operating horizon because the basis for planning horizon assessments [transmission planning system models (e.g. firm loads, firm transfers, and generation dispatch) and applicable contingencies] are quite different from the basis for operating horizon assessments. It also seems that the burden on the PCs to prepare the required information packages for potentially impacted RCs and TOPs will not be commensurate with the limited benefit that it may provide to RCs and TOPS. It would be more reasonable, clear cut, and pose less compliance risk to require PCs to simply provide their Near-Term Transmission Planning Horizon and Transfer Capability Assessments to the RCs and TOPS within and adjacent to their area. The RCs and TOPs would then decide from themselves whether any information in these documents may be interest or impact them.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
FAC-15-1 Requirement R6 is a step in the right direction. However, FAC-15-1 should address that Planning Assessments and Operations studies for derivation of SOLs and IROLs are not of the same scope in terms of number of facilities considered out of service. Therefore simply enforcing that the performance criterion used in the Planning Assessment be more restrictive than that used in Operations does not materially improve the operability of planned facilities. The scope of the studies in the Operations Horizon should be increased to bridge this gap through Requirements in FAC-11-4 and FAC-14-3.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No

Document Name	
Comment	
This would place too much additional compliance burden on the PC. If the RCs and TOPs believe that this information is important for them to obtain, a SAR should be opened to add this to the TPL-001 standard or at least the IRO-017 standard verses creating another new standard that requires the PC to provide additional information from the TPL standard to the RC and the TOP.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Because UFLS and UVLS relays are permitted to trip load beyond P2.1 contingencies in the Planning Assessment and will trip as needed to help stabilize the simulation, it is not possible for FAC-015-1 R6.4 to be achieved because the simulation will not reach the point of instability, Cascading, or uncontrolled separation with the relay action present in the simulation. In order to make this determination (whether there would have been instability, Cascading, or uncontrolled separation if they had not tripped), an entity would have to run a second set of simulations blocking all UFLS and UVLS relays from tripping. The system performance could then be assessed and the information in FAC-015-1 R6.4 related to UFLS and UVLS relays could then be provided. As these additional simulations would represent additional burden to the work performed under TPL-001-4, CHPD feels that the proposed FAC-015-1 R6.4 should have the items related to UVLS and UFLS removed from the criteria. If this is a reliability objective, it should be addressed under the TPL-001-4 standard.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Need more specific with property data especially “switching data”.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The use of the term "instability, Cascading, or uncontrolled separation" as stated in R6 may not be clear to all that the purpose is for the Planning Coordinator to alert the RC to scenarios that have the potential to be categorized as IROLs in the Operations arena based on the RC's SOL methodology. Suggest rewording R6 to: "Each Planning Coordinator shall communicate scenarios that demonstrated IROL type conditions such as instability, Cascading, or…….." However, it should be made clear that the RC would make the determination if it would be considered an IROL based on the RC's SOL methodology	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
R6 is better located in TPL-001-4 or FAC-013-2. The current language states that "any" instability, Cascading or uncontrolled separation should be communicated. Does the RC need or want to know about extreme disturbances or only P1-P7 events? It makes more sense to share the Planning Assessment and Transfer Capability assessments to the RC as part of the relevant standards.	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

This requirement is already included in other planning standards, such as TPL-001-4 and IRO-017-1. The objective could be better accomplished by modifying or including specific details of the requirement in existing planning standards.

IRO-017-1 requires the TPs and PCs to provide the system assessment to their RC. Any identified instability would be included in the system assessment. The RC is in the best position to inform the TOP in the RC area. TPL-001-4 also requires the PCs and TPs to share the system assessment to adjacent TPs and PCs.

Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	

This data is appropriate for the conditions and timeframes studied in the Planning Assessment. Additional operational analyses may be needed for particular operating conditions that are not part of the conditions and timeframes addressed by the Planning Assessment.

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	

PNMR agrees with the information provided in R6. However, PNMR believes that R6 should be included in TPL-001 and should not result in a new FAC standard.

Likes 0	
Dislikes 0	

Response

James Grimshaw - CPS Energy - 3

Answer	Yes
Document Name	

Comment

This data is appropriate for the conditions and timeframes studied in the Planning Assessment. Additional operational analyses may be needed for particular operating conditions that are not part of the conditions and timeframes addressed by the Planning Assessment.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy request further clarification from the drafting team on the types of events that require communication from the PC to the RC and TOP in R6. The current language states that the PC shall communicate to the RC and TOP of “any” instances of instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near [illegible] this include “extreme events” as well?

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak is especially supportive of subpart 6.4 which requires communication of “Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;” This information is critical for the RC understanding the risks that have been identified and the measures that were taken in the Planning Assessments to address the risk. If this information is not provided, the RC has no way of knowing or understanding what kinds of risks for instability, Cascading, or uncontrolled separation that were identified and successfully mitigated via the measures listed in subpart 6.4. This unawareness can have significant adverse reliability consequences if the associated automatic schemes are rendered unavailable in operations. It is critical that the RC understand the risks that were identified and the means by which those risks were mitigated in the Planning Assessment so that these risks can be addressed in operations through the development of Operating Plans.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

In addition to the communication of information to impacted RCs and TOPs, the NSRF believes consideration should be given to including impacted Transmission Planners as well. Although the information is needed primarily by the RCs and TOPs, there is not currently a mechanism to communicate the information back to the impacted TPs for continued awareness. To ensure all parties remain aware of potential issues identified in the assessments, LES recommends the following change to R6:

R6. Each Planning Coordinator, **in coordination with each impacted Transmission Planner**, shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near Transfer Capability Transmission Plann assessment to each impacted Reliability Coordinator and Transmission Operator.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Yes, I think it is appropriate to provide this information. As with above, I think it should be addressed in the TPL-001 standard (as part of R8 perhaps).	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	

In addition to the communication of information to impacted RCs and TOPs, LES believes consideration should be given to including impacted Transmission Planners as well. Although the information is needed primarily by the RCs and TOPs, there is not currently a mechanism to communicate the information back to the impacted TPs for continued awareness. To ensure all parties remain aware of potential issues identified in the assessments, LES recommends the following change to R6:

R6. Each Planning Coordinator, **in coordination with each impacted Transmission Planner**, shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near Transfer Capability Transmission Plann assessment to each impacted Reliability Coordinator and Transmission Operator.

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SCE recommends one more additional sub-bullet be added such that the PC shall communicate any assumptions of system conditions critical in its identification of instability, Cascading or uncontrolled separation (such as load levels, local generation assumptions, etc). It is probably obvious but R6 does not currently require it.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

Yes, I think it is appropriate to provide this information. As with above, I think it should be addressed in the TPL-001 standard (as part of R8 perhaps).

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal	

Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
As required by TPL 001-4, planning coordinators implement corrective action plans for any instability, Cascading, or uncontrolled separation identified in planning assessments due to planning events involving single or multiple contingencies. Providing this information to RC may be useful if the corrective action plan is establishing an SOL. On the other hand, providing this information to RC may not be useful if the corrective action plan is transmission development.	
Likes 0	
Dislikes 0	
Response	

15. Do you agree that the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Reference justification and alternative language proposed as part of the answer for the previous question (i.e., Question 14).

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

See the response to Q16.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

FAC-013 (TTC) is not required to have stability criteria, instability criteria, document UFLS or UVLS relay operation, or include Corrective action plans. It is recommended that the reference to the Transfer Capability assessment be removed from the proposed FAC-015-1 R6.

Likes 0	
Dislikes 0	

Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Please refer to the comments submitted by the SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
Development of SOLs and IROLs is the appropriate assessment for identifying any instability, Cascading, or uncontrolled separation in the planning horizon that is not mitigated by corrective action plans such as transmission development. TPL001-4 planning assessments require the PC to model peak load and firm transmission services but do not require stressing the system to identify its limits. Transfer Capability assessment is only applicable to tie lines.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Planning assessments in TPL-001-4 are the appropriate assessments to identify system instability and cascading outages in the planning horizon. However, BPA does not see a need for a new standard. The objective is already addressed by TPL-001-4.	
Likes 0	
Dislikes 0	

Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes, with the same comment as question 14, with the addition that the FAC-013 standard is the appropriate place to require supplying Transfer Capability Assessment results to impacted RCs and TOPs.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Based on the requirements of the new TPL-001-4, the Planning Assessment must identify any Near-Term Transmission Planning Horizon instability, Cascading or uncontrolled separation. The proposed FAC-015-1 R6 correctly references the reliability objective accomplished by TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Reclamation supports the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, because these items properly identify potential risks.	
Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
These assessments look at extreme disturbances or non-firm transfers and would be the appropriate studies in the Planning Horizon that would be able to identify instability, Cascading or uncontrolled separation if these concerns existed.	
Likes 0	
Dislikes 0	
Response	

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Yes, with the same comment as question 14, with the addition that the FAC-013 standard is the appropriate place to require supplying Transfer Capability Assessment results to impacted RCs and TOPs.	
Likes 0	
Dislikes 0	
Response	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
As the Near-Term Transmission Planning Horizon is the closest to operating horizons, these are the most relevant results to pass on to those responsible for operating the system.	
Likes 0	

Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
The assessments applicable to R6 should be reflective of those assessments required by the NERC Reliability Standards. Both Planning Assessments and Transfer Capability assessments are required by the standards. Furthermore, it is possible that when performing Transfer Capability assessments, the first limitation encountered could be a stability limit (i.e., as power is transferred across an interface, a stability limitation is reached before any thermal or steady-state voltage limitation is reached). Because this is an operational possibility, Peak believes that Transfer Capability assessments should be included in R6. Peak also believes Transfer Capability assessments should be included in R1 through R3.	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	

Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

The PC also needs to send the results of its Planning Assessment or Transfer Capability Assessment to its Transmission Planners. This activity should happen before the results are sent to the RC and TOP.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	Yes
Document Name	

Comment

Note: CAISO does not support this response.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

Near-term TP horizon is the closest to operating horizon

Likes 0	
Dislikes 0	

Response

James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
One of the purposes of the Planning Assessment is to capture any anticipated instability, Cascading or uncontrolled separation in the near-term and long-term transmission planning horizons.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We concur that both assessments for the Near-term Planning Horizon under TPL-001 and for transfer capability under FAC-013 are appropriate to be used because they are the closest to the Operations Horizon.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
PNMR agrees with the assessments as stipulated in R6, however, PNMR believes that R6 should be included in TPL-001 and should not result in a new FAC standard.	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
One of the purposes of the Planning Assessment is to capture any anticipated instability, Cascading or uncontrolled separation in the near-term and long-term transmission planning horizons.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon. However, due to BES system topology differences between the Planning Horizon (usually all facility in-service) and Operations Horizon (N-1 or N-1 out of service due to planned or forced) then instability, Cascading, or uncontrolled separation MAY NOT be identified in the Planning Assessment during the Near-Term Transmission Planning Horizon and the Transfer Capability assessment. In the Operations Horizon, the Operating Planning Analyses (OPA) could and may still identify instability, Cascading, or uncontrolled separation due to latest BES modeling to real-time. Also, the requirement for communicating Facility Rating appears to be redundant to the FAC-008 Reliability Standard.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
We think that it is unnecessary and less worthwhile to include the Long-Term Planning Horizon (6 - 10 years in the future) because the future system assumptions (load, generation, transfers, etc.) are more uncertain and speculative than the Near-Term Planning Horizon. So, the results would be less useful and subject to change than the Near-Term Planning Horizon results.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

16. If you have any other comments that you haven't already provided in response to questions 11-15, please provide them here.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT Comments:

Requirements R1, R2, and R3 contain similar language that generally requires the PC's Planning Assessments to use limits that are "equally limiting or more limiting" than the limits established pursuant to the RC's methodology. Each of these requirements also includes a second sentence that appears to allow the PC to use a less limiting value when the PC has a legitimate technical justification for doing so. This second sentence technically contradicts the first sentence. ERCOT proposes additional revisions to clarify that the second sentence operates as an exception to the first sentence.

Also, Requirements R1, R2, and R3 do not specify whether the technical justification provided by the PC must be acceptable to (or accepted by) the RC. In the event of a disagreement between the PC and RC, ERCOT suggests that the rule should be clear as to which entity's determination prevails. ERCOT presumes the RC's determination should prevail in such an event since the RC has ultimate responsibility for overseeing the SOL methodology under proposed FAC-011, Requirement R1. Allowing the PC what amounts to unilateral discretion in establishing limits would undermine the principle that the RC's SOL methodology should generally govern, as reflected in the first sentence of Requirements R1, R2, and R3 in FAC-015. ERCOT therefore recommends revisions to the last sentence of each of these three requirements.

The following revisions reflect both of the changes described above:

R1. Each Planning Coordinator, when developing its steady -state r
Ratings used in its Planning Assessment of the Near -Term Transmission Plar than those established
in accordance with its Reliability Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may*** use less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology ***if***, the Planning Coordinator ***provides*** a technical justification ***that is accepted by*** its Reliability Coordinator.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the
Near -Term Transmission Plar ccordance with its
Reliability Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may use*** less limiting System steady -sta
System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology if the Planning Coordinator ***provides*** a technical justification t***hat is accepted by*** its Reliability Coordinator.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the
Near -Term Transmission Plannin specified in its Reliability
Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may use*** less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology if the Planning Coordinator ***provides*** a technical justification t***hat is accepted by its*** Reliability Coordinator.

****Please refer to the attached comment form for redlined language.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

1. We ask the SDT to clarify that references to a RC's SOL Methodology is done, as required, per Reliability Standard FAC-011-4. The proposed standard does not make this distinction.
2. The VSLs identified for Requirement R4 do not identify a failure to provide SOL information to requesting PCs.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

National Grid supports the NPCC RSC Group comments.

Additional comments for consideration:

There is potential area of concern as to why the TP is not included in the PC's communication of any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment FAC-015-1, Requirement R6.

Due to lack of consistent definitions/terminology related to definitions of stability concepts regarding both transient stability and small signal-stability (as related to angle stability) as well as voltage stability, the requirement to implement a process related to the stability performance criteria in Requirement R3 (et.al.) is not clearly defined. We suggest revising by using language related to Requirement R4 and R5 in NERC Reliability Standard TPL-001-4, which states that each TP and PC shall have "criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System" and "criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System."

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	
Document Name	

Comment

Not applicable.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	
Document Name	

Comment

This comment is regarding to R4 of FAC-015-1. R4 stated that "Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's". Entities understand that there will need to be two-ways communication between Planning Coordinator (PC) and Transmission Planner (TP). With that said, TPs are much closer to the source of 'Facility Ratings and System steady-state voltage limits'. It would make better sense for TP to provide 'Facility Ratings and System steady-state voltage limits' to PC and consistent to the current practice of TOPs providing 'Facility Ratings and System steady-state voltage limits' to the RC. The R4 as proposed is as having the RC providing 'Facility Ratings and System steady-state voltage limits' to TOPs. As proposed R4, the PC will need to request the 'Facility Ratings and System steady-state voltage limits' from the TP and/or TPs and then the PC will just provide back to the TP/TPs. As drafted, R4 is an effort that involved extra man power and time with no benefit.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

James Grimshaw - CPS Energy - 3

Answer	
Document Name	

Comment

FAC-015 Requirement R5 is inappropriately placed outside of the TPL-001 standard. We believe all requirements to perform the Planning Assessment should be housed within the TPL-001 standard to avoid confusion or double work.

Likes 0	
Dislikes 0	

Response

Gladys DeLaO - CPS Energy - 1

Answer	
Document Name	

Comment

FAC-015 Requirement R5 is inappropriately placed outside of the TPL-001 standard. We believe all requirements to perform the Planning Assessment should be housed within the TPL-001 standard to avoid confusion or double work.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	

Document Name	
Comment	

FAC-15-1 is a step in the right direction. However, FAC-15-1 should address that Planning Assessments and Operations studies for derivation of SOLs and IROLs are not of the same scope in terms of number of facilities considered out of service. Therefore simply enforcing the performance criterion used in the Planning Assessment be more restrictive than that used in Operations does not materially improve the operability of planned facilities. The scope of the studies in the Operations Horizon should be increased to bridge this gap through Requirements in FAC-11-4 and FAC-14-3.

Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	
Comment	

PNMR seeks clarification on the use of single contingency criteria. FAC-011-4 defines a single contingency as a TPL-001 P1 event. In TPL-001 categories P1 and P2 are labeled single contingency. If the RC defines criteria for single and multiple contingency based on FAC-011-4, will the criteria for the single contingency be used for both P1 and P2 events of TPL-001 even though the contingency definition of P2 does not match the single contingency definition in FAC-011-4?

PNMR believes that FAC-015 has requirements that should be part of the TPL-001 Planning Assessment. Instead of creating a separate standard, PNMR recommends that TPL-001 should be revised to include the new requirements.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	
Comment	

The work identified in FAC-015 would be better positioned in the TPL-001 standard. A SAR should be drafted to open the TPL-001 standard to include those required items from this proposed new standard rather than creating a new standard. Coordination of criteria could then be determined between the TP and PC as identified in the TPL-001 standard R7 rather than by this new standard by parties familiar with the information in the local regions.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	

More clarification is needed related to the identification of Facility Ratings. As the Transmission Owners are already obligated to provide planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation). The drafting team should clarify that asset owners typically provide multiple ratings for a given asset based on various conditions and the intent of this standard is to ensure how the RC and PC pick those ratings is consistent.

Note: ERCOT does not support this response.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The existing FAC-010, FAC-011, and FAC-014 framework provides the required coordination between planning and operation horizons from the planning coordinator perspective.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	
Document Name	
Comment	

More clarification is needed related to the identification of Facility Ratings. As the Transmission Owners are already obligated to provide planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation). The drafting team should clarify that asset owners typically provide multiple ratings for a given asset based on various conditions and the intent of this standard is to ensure how the RC and PC pick those ratings is consistent.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	
Document Name	

Comment

It appears that one of the objectives here is for the Planning Coordinator to make the Reliability Coordinator aware of system issues identified in the Planning Assessments that could impact the Operations timeframe. CHPD recommends that the TPL-001-4 standard, R8, be modified to add the Reliability Coordinator to the distribution of the Planning Assessment by the Planning Coordinator and Transmission Planner to adjacent Planning Coordinators and Transmission Planners. TPL-001-4 R8 allows the Reliability Coordinator to request this document already, but it would make sense to add the Reliability Coordinator (and possibly Transmission Operator) to the mandatory Planning Assessment distribution in order to pass on the issues observed in the assessment of planned operations for the planning horizon.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

It seems to us that proposed standard FAC-015 is missing a requirement (R7) for the Transmission Planners to communicate any instability, Cascading, or uncontrolled separation in either its Planning Assessment information to its TOP, PC, and RC (similar to R6). This requirement would be a slight expansion of IRO-017-1 R3 and consideration should be given to moving this requirement to the new FAC-015-1 standard to keep all TP applicable items together.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections:

1. Violation Severity Levels
   i. Requirement R4 VSL
      a. The second part of the High and Severe VSL is confusing as it references “information” while Requirement R4 references “criteria”. ReliabilityFirst recommends the following for consideration:
         1. The Planning Coordinator failed to provide one element of the required criteria (i.e., Facility Ratings, System steady -st Coordinator’s.
      b. The language of the first part of the High and Severe VSL are completely the same. Since there is no reference in any of the VLSs related to providing criteria to the requesting Planning Coordinators, ReliabilityFirst believes the first part of the Severe VSL should state “… to its requesting Planning Coordinators” instead of “… to all of its Transmission Planners.”

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	
Refer to comments submitted by SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	
Document Name	
Comment	
Peak believes that the Transmission Planner should be included along with the Planning Coordinator for communicating any instability, Cascading, or uncontrolled separation in FAC-015-1 requirement R6. Both Planning Coordinators and Transmission Planners perform Planning Assessments for the Near-Term Transmission Planning Horizon, therefore, it is possible that either entity could identify instability, Cascading, or uncontrolled separation in their Planning Assessments. The revised language could read, “Each Planning Coordinator and Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. Transmission Planners are not required to perform Transfer Capability Assessments, so any revised language might need to account for that.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	

Document Name	

Comment

The stated purpose of FAC-015-1 is:

"To ensure the Facility Ratings, System steady-state voltage limits, and stability [performance] criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology."

LSPT does not disagree with this purpose. It requires two-way communications between the RC and its TOPs and the PC and its TPs. However, LSPT proposes a more efficient way to meet this purpose.

Alternate FAC-015-000 Proposal

There are 15 Reliability Coordinators (per the NERC Compliance Registry) in the NERC footprint and they are listed below. Except for VACAR South and Peak Reliability, the rest are also registered as Planning Coordinators. In total, NERC has 78 Planning Coordinators are registered.

Reliability Coordinators in NERC (as of 9/29/2017)

1. Midcontinent Independent System Operator, Inc.
2. Saskatchewan Power Corporation
3. Southwest Power Pool
4. Hydro-Quebec TransEnergie
5. ISO-NE
6. New Brunswick Power Corporation
7. New York Independent System Operator
8. Ontario IESO
9. PJM Interconnection, LLC
10. Florida Reliability Coordinating Council, Inc.
11. Southern Company Services, Inc. - Trans
12. Tennessee Valley Authority
13. VACAR South
14. Electric Reliability Council of Texas, Inc.
15. Peak Reliability

As an alternative to the present FAC-015-1, LSPT suggests requiring each Reliability Coordinator to facilitate collaborative discussions with its Transmission Operators that use its SOL Methodology and with the Planning Coordinators and Transmission Planners in its Reliability Coordinator Area. Those discussions would be bounded by stated purpose of the proposed FAC-015-1 standard. The results of such discussions would be documented to identify any reliability-related gaps between operations and planning and vice versa regarding the purpose of the standard. For any identified gaps, the RC would be required to develop and implement a Corrective Action Plan. Progress on CAPs would be required to be collectively reviewed periodically (LSPT suggests this be no more than annually).

This is a far more efficient approach to address the standard’s purpose.

Comments on FAC-015-1 as proposed

LSPT is pleased that the retirement of FAC-010-3 eliminated the unnecessary requirement for PCs to develop an SOL Methodology and use that methodology to develop SOLs and IROLs for the planning horizon. Although FAC-015-1 carried over language from the proposed retired FAC-010-3 and proposed revised FAC-014-2, LSPT does not agree with the requirements that FAC-015-1 would impose upon PCs and their associated TPs.

Per R1 through R5 in FAC-015-1, the Planning Assessment in R6 must either use the Facility Ratings, System steady -s performance criteria from the RC’s SOL Methodology *or* provide a technical justification to the RC if the PC’s values differ from the RC’s values. The RC is not subject to the standard, and as written, no method is proposed to resolve technical differences between the RC and PC.

There are many good reasons for differences between a Planning Assessment and an Operational Planning Assessment. For example, some RC’s use a defined set of Normal and Emergency Facility Ratings based upon various ambient temperatures, including daytime and nighttime rating reflecting solar impacts. These ratings cover conditions that will be experienced by operators. Planner’s typically use some of the RC’s ratings as its ‘seasonal ratings’ that, when combined with the temperature impacts of load, stress the System. Each is correct in its application.

The end product in R6 is a Planning Assessment in the Near-Term Planning Horizon along with Corrective Action Plans for any deficiencies. This is well beyond FAC-015-1’s stated purpose. In addition, it is largely duplicative or in TPL-001-4 requirements (see R2.7 in TPL-001-4), except that the implementation of TPL-001-4 would use planning and not operating assumptions.

- The R6 phrase “or its Transfer Capability assessment” would not be produced in TPL-001-4. The SDT did not provide any rationale for this language.

- FAC-015-1 does not state whether the PC and TP are required to use the SOL Methodology’s Contingency List or its planning Contingency list per TPL-001-4.

In summary, FAC-015-1 places significant requirements on PCs and their TPs, and these requirements are not required to meet the standard’s purpose. The main rationale for the FAC-015-1 requirements appears to be that they came from standards being retired (FAC-010-3) or revised (FAC-014-2). The SDT should justify the requirements on their own merits independent of previous standards.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

R4 – would prefer to see something about requesting Planning Coordinators with a reliability need instead of any Planning Coordinator that requests.

R6 – could consider including what is provided to impacted RCs in the IRO-017 or TPL-001 standard. This seems to have requirements for the

Planning Assessment scattered over 3 standards.

R6 – would have preferred use of the term “IROL like conditions” instead of words copied from the IROL definition.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	
Document Name	

Comment

One area of coordination that is missing is having the PC review stability limits or IROLs determined by the Transmission Operator and/or Reliability Coordinator, especially in cases where the limit was not determined by the PC – possibly because the PC only considered firm uses as per TPL-001-4 R1.1.5 or Transfer Capability assessment methodology (FAC-013-2 R1) did not stress the same area as the operating assessments. The PC may want to consider the identified stability limit for future confirmation in a Planning Assessment or Transfer Capability Assessment. The criteria for the selection of transfers to be assessed (FAC-013-2 R1.1) could be based on review of information provided to the PC from the RC/Transmission Operator. It is preferable to modify FAC-013-2 to address this issue rather than include in FAC-015.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	
Document Name	

Comment

Note: While we agree with the retirement of FAC-010, and revisions to FAC-011 and 014 we will be voting “No” because of our concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The NSRF remains concerned with the proposed definition of “System Voltage Limit” as the phrase “reliable system operations” was replaced with “acceptable System performance.” Acceptable System performance should rely on, among other factors, the definition of SOL Exceedance which is in a separate ballot and ballot period. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. The NSRF remains concerned with unintended impacts of separating the standard and the proposed SOL definition. The NSRF also has this concern with the following question.	
Likes 1	Tay Sing On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5;
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment on this new standard. However, BPA does not see the need to create new planning standards to accomplish the goals. Most of the requirements are either partially or fully included in other planning standards. The objectives could be better accomplished by adding or modifying existing planning standards.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
Note: While we agree with the retirement of FAC-010, and revisions to FAC-011 and 014 we are voting “No” because of our concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	

Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
In regards to the proposed R5 (for which no questions have been asked by the SDT), why was “System steady-state voltage limits” used within this obligation rather than the newly proposed “System Voltage Limit?”	
Likes 0	
Dislikes 0	
Response	
Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	

Response

17. Do you agree with the proposed definition of System Voltage Limit? If not, please explain and provide alternative language.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Within the definition itself, is the word “limits” the best choice for supposedly indicating that it is a numerical value? Instead, might this be more appropriate? “*The maximum and minimum steady-state *voltage* ~~limits~~ (both normal and emergency) that provide for acceptable System performance.*”	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends including separate definitions for minimum steady -state voltage and maximum -state Minimum steady voltage limits ensure acceptable power system performance while maximum steady -state voltage limits ensure ratings are not exceeded. The approaches for determining and responding to exceedances are different for each type of voltage limit (minimum and maximum). BPA therefore proposes the following revisions to the definition of System Voltage Limit: “The minimum steady -state voltage (both pre-Contingency and post-Contingency) that provide for acceptable System performance. The maximum steady -state voltages based ... performance.”	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	No
Document Name	

Comment	
As currently written, the words maximum and minimum introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, LES recommends the following change: The steady-state voltage limits, **including both normal and emergency with applicable allowable timeframes**, that provide for acceptable System performance.	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
As currently written, the words *maximum* and *minimum* introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, the NSRF recommends the following change: The steady-state voltage limits**, including both normal and emergency with applicable allowable timeframes,** that provide for acceptable System performance.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy generally agrees with the proposed definition; however, we believe that the phrase, “acceptable System performance” could be subjective. System Voltage Limits should always respect, both in normal and emergency conditions, SOLs and IROLs, both of which are defined and measurable. CenterPoint suggests the following definition of System Voltage Limit for the SDT to consider: “The maximum and minimum steady -state voltage limits (both nor of the BES.” As a point of reference, the NERC glossary defines Reliable Operation as: “Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a	

result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to "Actual flow through a Facility is above the Facility’s Rating and the associated allowable time frame is exceeded.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
The existing constructs (Facility Ratings, voltage performance criteria, voltage stability/reactive margin) should be adequate to address high voltage conditions (typically through Facility Ratings) and low voltage (typically through voltage performance criteria and voltage stability/reactive margin). CHPD feels that introducing another voltage-limit term will only serve to confuse the meanings of these other terms. Additionally, CHPD feels it would have a greater reliability for NERC to develop a system voltage whitepaper to discuss various voltage Facility Ratings methods and the reliability concerns that should be addressed with low and high voltage performance criteria, as well as revisiting transient and reactive margin concepts. A whitepaper would help clarify expectations, bring useful dialogue and improve industry knowledge in this area, whereas a third defined term describing voltage will not likely bring the desired clarity. CHPD does not recommend the creation of the term ‘System Voltage Limit’.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with other commenters that suggest the word “limits” should be removed from the System Voltage *Limit* definition	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
As currently written, the words maximum and minimum introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, ITC recommends the following change: The steady-state voltage limits, including both normal and emergency with applicable allowable timeframes, that provide for acceptable System performance.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Concerns with the unapproved SOL and SOL Exceedance definitions and their applicability to this definition.	
Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR proposes removal of the phrase “(both normal and emergency)”. In the rational the SDT stated they wanted to allow flexibility but including normal and emergency requires the establishment of multiple limits without guidelines of what the limits will address, i.e. finite time period, type of outage.	
Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
To provide additional clarity and consistency with the proposed NERC Glossary Term, *System Operating Limit*, we recommend the proposed *System Voltage Limit* (SVL) definition affirmatively state SVLs are used in the operation of the BES. **Proposed alternative language**: “The maximum and minimum steady-state Facility voltage limits (both normal and emergency) used in the operation of the Bulk Electric System.”	
Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
ATC does not believe there is a need for the term System Voltage Limit. The current FAC-008-3 standard already requires GOs and TOs to determine	

Facility voltage Ratings, and these ratings are already captured by the current SOL definition. Therefore, there is no need for the proposed definition of System Voltage Limit.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

However, this proposal seems to be redundant with the FAC-008 voltage limit already established.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

SRP generally supports the proposed definition. However SRP will be voting Negative on the ballot due to recommended changes to the proposed standards.

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak agrees with the proposed definition for System Voltage Limit.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment

As a result of this change, does the definition of Facility Rating also need to change to remove "the maximum or minimum voltage" part of that definition?

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	

Comment	
The SDT should consider a reference to facility voltage rating. The clarification should be provided that illustrates the relationship similar to between thermal facility rating and System Operation Limit; and facility voltage rating and System Voltage Limit.	
Likes 0	
Dislikes 0	
Response	

18. Do you agree with the Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
This is a significant paradigm shift for industry, affecting personnel from both operations and planning on how SOLs are handled and used within assessments. Time is needed to coordinate activities, particularly between RCs and PCs on how information is dispersed to TOPs and TPs, respectively. Additional time will also be needed for training that will include a larger audience than just operating personnel identified for Reliability Standard PER-005-2. Moreover, depending on the significance of a compliance burden introduced by these standards, registered entities will need time to procure additional staff and resources for their established compliance programs. We believe an implementation period no less than 24 months is appropriate.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that the implementation time frame should be a minimum of 36 months to allow active participation by all impacted entities especially PA and TOPs since as written, FAC-011 and FAC-015 will require the PA and TOP to plan and operate their system to new system performance criteria.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The 12 month implementation plan is only sufficient to put in place the required processes necessary to facilitate the requirements as stated in the new and revised standards. In order to then allow for a cycle of the TPL-001 standard to also be accommodated to facilitate this new SOL process another	

12 months would need to be added into the implementation plan to allow for this work specifically.

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	No
Document Name	

Comment

The new term and new/revised standards require Responsible Entities to develop a methodology and to establish further coordination between the RCs and TOPs. These efforts require more than 12 months for adequate development time and coordination between Responsible Entities. AECI recommends that the implementation plan should be extended to 24 months to allow Responsible Entities the time needed to implement the new/revised standards.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

Standards need additional modification – once this is done, the proposed Implementation Plan can be assessed.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Based on the level of work that is anticipated, Duke Energy does not agree with the proposed Implementation Plan, and recommends that the drafting team consider extending the Implementation Plan to 24 months.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli

Answer	No
Document Name	

Comment

The new term System Voltage Limit and requirements in FAC-011-4 R3 will require methodology development and coordination between the RC and TOPs to address common limits as well as coordination. Once complete, the studies will need to be performed based on these new concepts, which may take more than 12 months. Also, the language in FAC-011-4 R2 is a change which will result in the need to address common limits as well as coordination.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

City Light would like to see the standard resolution first.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

As documented above, BPA does not believe a new standard needs to be created.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	

Comment

Peak agrees with the proposed implementation plan.

Likes 0	

Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP generally supports the proposed Implementation Plan. However SRP will be voting Negative on the ballot due to recommended changes to the proposed standards.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	

Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

19. The SDT asserts the combination of proposed FAC-011-4, FAC-014-3, and FAC-015-1 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As documented above, BPA does not believe a new standard needs to be created.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation has concerns with possible misinterpretation of FAC-011-4 R4.2 and R5 as it implies Real-Time Assessments will include Stability. Reclamation also does not agree with the identified single Contingency and multiple Contingencies for use in determining stability limits because the TOP will inform the RC which Contingencies are credible.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
As proposed, we perceive this Standard as requiring additional resources for stability studies and compliance documentation such that it will add cost to our business. Furthermore, the proposed Standard will not change the way we increase reliability or operate the system.	

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

Changes proposed to FAC-011-4 and FAC-014-3 as well as the retirement of FAC-010-3 are reasonable. The development of FAC-015 seems to be burdensome, especially the Facility Rating comparison exercise. Some of the proposed changes fit better into existing standards TPL-001 and FAC-013.

Likes 1	Michael Watkins, N/A, Watkins Michael
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

LSPT's proposed alternative to FAC-015-1 in Q16 meets the proposed standard's purpose in a more efficient manner.

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

Only consistency in requirements and criteria would help to increase "cost effectiveness" in our environment where legal/regulatory approval processes

impede the effort in maintaining system reliability.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The method that the set of standards has been put together forces everyone into a defined process rather than defining the objective of the standard and allowing every group to identify their own cost effective method of accomplishing the objective. The organization of the requirements especially with those found in FAC-015 should have been incorporated in other already existing standards (TPL-001 or IRO-017). This new proposed standard is not cost effective and sets up organizations for compliance risks due to developing a third standard with obligations tied to the TPL-001 standard that should have just been added to this standard.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We do not see any flexibility to meet the objectives. For standard FAC-015-1, we have offered alternative ideas that the PC and RC should be providing technical justification for developing more stringent system performance requirements than the system is presently planned. We believe that if the draft language remains unchanged, depending on the imposed requirement by the PC or RC, significant dollars may need to be expended to meet the new, more stringent requirements.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No

Document Name	
Comment	

PNMR believes that the proposed FAC-011 and FAC-015 allow one entity, the RC, to change long standing system performance criteria used by entities for the operation and planning of the system which could result in the need to implement numerous system changes to meet the RC's criteria.

Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	
Comment	

ATC is concerned with the application of the RC SOL methodology to the TOP through FAC-014-3 with respect to the requirements regarding stability limits and stability analysis in FAC-011-4 R4 and R5. The current proposal may require a significant increase in stability analyses, whether in OPAs and RTAs, that are not warranted in a local TOPs system but is mandated because a TOP must follow an RC's one-size-fits-all metholodgy.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	

1. The proposed standards require direct communication between the RC and the impacted entities that would be documented through electronic communications or voice recordings. This approach is cumbersome and inefficient. We believe the standards should instead allow entities to use more automated mechanisms for exchanging SOL information.
2. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	
Response	

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes

Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
Workload and operational impacts are likely to be in-line with current practice. While FAC-010 is proposed to be removed, FAC-015 replaces it, so the baseload compliance workload remains unchanged.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA believes the overall approach can be a cost effective manner to meet the reliability objectives, provided that the scope of activities for each involved functional entity is made abundantly clear so that unnecessary or duplicative work is not required. We believe additional changes, as suggested above, are needed to reach that point.	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	
Some of the proposed requirements, (for examples: Requirement R3, Parts 3.1 in FAC-011-4), could result in unnecessary cost for the responsible entities without any reliability benefits. We urge the SDT to consider adopting our proposed wording changes to achieve a more cost-effective approach to meeting the reliability objectives.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	Project 2015-09 Establish and Comm SOL.docx
Comment	

Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2015-09 Establish and Communicate System Operating Limits | FAC-011-4, FAC-014-3, FAC-015-1, Implementation Plan, System Voltage Limit
Comment Period Start Date:	9/29/2017
Comment Period End Date:	11/14/2017
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-011-4 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-015-1 IN 1 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan IN 1 OT 2015-09 Establish and Communicate System Operating Limits System Voltage Limit | New Definition IN 1 DEF

There were 56 sets of responses, including comments from approximately 166 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT is recommending retirement of FAC-010-3 and has provided justification in the “FAC-010/FAC-015 Rationale” and “FAC-010-3 Mapping Document.” Do you agree that the proposed retirement of FAC-010-3 does not create a reliability gap? Please provide supporting rationale.

2. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.1 and R2.2, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

3. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.3 and R2.4, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

4. Are there any reliability objectives of FAC-011-3, Requirement R2, R2.3 and R2.4 that you maintain need to be preserved in requirements relating to the development of Operating Plans which would reside outside the FAC family of standards? Please explain your response.

5. Do you agree that the SDT should allow the use of UVLS in the establishment of stability limits? If not, please explain and provide alternative language.

6. If you have any other comments that you haven’t already provided in response to questions 2-5, please provide them here.

7. The SDT is proposing to divide existing Requirement R1 of FAC-014-2 into three requirements in FAC-014-3 to clearly indicate which entities have the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) [the RC], System Operating Limits

(SOLs) [the TOP] and stability limits that impact more than one TOP in its Reliability Coordinator Area [the RC] into proposed Requirements R1, R2, and R4, respectively. Do you agree with the proposed changes? If not, please explain.

8. Existing FAC-014-2, Requirement R5, R5.2 requires the Transmission Operator (TOP) to provide its SOLs to its Reliability Coordinator (RC) and Transmission Service Providers (TSPs) that share its portion of the RC Area. The SDT is proposing in Requirement R3 of FAC-014-3 to exclude the TSPs from that communication chain. Other requirements in existing standards (MOD-028-2, Requirement R7, MOD-029-2a, Requirement R4, and MOD-030-3, Requirement R2.6) require the TOP to provide the Total Transfer Capabilities (TTCs), Total Flowgate Capabilities (TFCs), along with supporting information and assumptions to TSPs. Because the TTCs and TFCs already reflect the impact(s) of any SOLs, the SDT deemed retention of the existing language unnecessary. Do you agree with the proposed change? If not, please explain.

9. The SDT relocated the reliability objectives of existing Requirement R6 of FAC-014-2 into Requirement R6 of proposed Reliability Standard FAC-015-1 such that all Planning Coordinator and Transmission Planner responsibilities will be housed within one standard. Do you agree with the proposed change? If not, please explain.

10. If you have any other comments that you haven’t already provided in response to questions 7-9, please provide them here.

11. FAC-015-1 is predicated on the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative/restrictive/limiting than those found in (or established in accordance with) the RC’s SOL Methodology, allowing for justified exceptions. Do you agree with this principle? If not, please explain.

12. Do you agree that coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria as required in Requirements R1-R3 should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

13. In Requirements R1 – R3, the SDT is proposing to allow a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology. Do you agree that this provides adequate flexibility (in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized; e.g., up-rating a line in a future project) without compromising reliability? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

14. Do you agree that the information identified in Requirement R6 is necessary for each impacted RC and TOP to properly evaluate instability, Cascading, or uncontrolled separation identified in planning assessments for use in establishing stability limits and IROLs in the operations horizon? If not, please explain and provide alternative language.

15. Do you agree that the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

16. If you have any other comments that you haven't already provided in response to questions 11-15, please provide them here.

17. Do you agree with the proposed definition of System Voltage Limit? If not, please explain and provide alternative language.

18. Do you agree with the Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.

19. The SDT asserts the combination of proposed FAC-011-4, FAC-014-3, and FAC-015-1 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Lucia Beal	Southern Maryland Electric Cooperative	3	RF

					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Midwest Reliability Organization	Cynthia Kneisl	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casuscelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO

					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO

Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC

					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Janis Weddle	6		Chelan PUD	Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
Associated Electric Cooperative, Inc.	Mark Riley	1		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC

					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO

					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion NextERA Con-Ed	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC

					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC

Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					j.Scott Williams	City Utilities of Springfield, MO	1,4	SPP RE
					Deborah McEndaffer	Midwest Energy, Inc	NA - Not Applicable	SPP RE
					Robert Gray	Board of Public Utilities (BPU), Kansas, City	NA - Not Applicable	SPP RE
					Steve McGie	Board of Public Utilities (BPU), Kansas, City	NA - Not Applicable	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE

1. The SDT is recommending retirement of FAC-010-3 and has provided justification in the "FAC-010/FAC-015 Rationale" and "FAC-010-3 Mapping Document." Do you agree that the proposed retirement of FAC-010-3 does not create a reliability gap? Please provide supporting rationale.

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
FAC-010-3 contains regional differences (e.g. common corridor 500 kV outages, no cascading for loss of two PV units) that the California ISO plans the WECC system to that provide for a more resilient system. With the exception of this Question and Question 15, the California ISO supports the comments of the ISO/RTO Council Standards Review Committee. However, the California ISO has provided numerous additional comments in the sections below related to the new proposed FAC-015-1 standard.	
Likes 0	
Dislikes 0	
Response	
The Contingencies and performance criteria contained in the Regional Differences section (E) are consistent with and can be addressed through studies that support TPL-001 compliance. This supports the SDT's contention that FAC-010 is redundant with not as comprehensive as TPL-001.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
SCE agrees with the drafting team that the new TPL-001-4 ensures the reliable planning of the transmission system and addresses each of the reliability components of FAC-010-3. The mapping document adequately and exhaustively demonstrates where the components of FAC-010 are addressed in other standards or are no longer relevant under the new SOL/IROL construct.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the SDT's rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment
Yes, I agree that it is unnecessary to have a planning SOL methodology. The TPL requirements along with changes to FAC-011, FAC-014 and the new requirements discussed in the FAC-015 (which I think should be covered in the TPL standard, but my comments on that are covered in the FAC-015 section) adequately define what ratings/limits should be used to plan the system. **Note:** While we agree with the retirement of FAC-010, we will be voting "No" because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response
Thank you for the comment.
Wendy Center - U.S. Bureau of Reclamation - 5

Answer	Yes
Document Name	

Comment
Reclamation supports retiring FAC-010-3 because the requirements are adequately addressed in other NERC Standards.

Likes 0	
Dislikes 0	

Response
Thank you for the comment.
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	Yes
Document Name	
Comment	

FAC-010 has always had minimal reliability value as it was restating what was already occurring as part of the TPL standards. Manitoba Hydro agrees the FAC-010-3 is completely redundant with TPL-001-4.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	Yes
Document Name	
Comment	

Yes, I agree that it is unnecessary to have a planning SOL methodology. The TPL requirements along with changes to FAC-011, FAC-014 and the new requirements discussed in the FAC-015 (which I think should be covered in the TPL standard, but my comments on that are covered in the FAC-015 section) adequately define what ratings/limits should be used to plan the system.

Note: While we agree with the retirement of FAC-010, we will be voting “No” because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the retirement of FAC-010-3 as part of this project. However SRP will be voting Negative on the ballot due to recommended changes with the other proposed standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees that the retirement of FAC-010 does not create a reliability gap. The SDT did a thorough job in their assessment of FAC-010 in the mapping document. As is pointed out in the supporting documentation, there is an abundance of redundancies between FAC-010 (and the associated requirements in FAC-014) and TPL-001-4. Peak supports the retirement of FAC-010 and the addition of FAC-015 as described in the supporting documentation.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Requirements in FAC-010-3 are covered by TPL_001_4	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes

Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Entergy agrees with the mapping document, the reliability impact is covered elsewhere.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	

Comment	
The coordination between the Planning and Operations horizons can and should occur without the added confusion of having a separate set of planning SOLs/IROLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SDT's intention is to remove the ambiguity associated with potentially conflicting SOL methodologies.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
CHPD confirms that it views the reliability function of FAC-010-3 to be duplicative of those objectives also contained in the TPL-001-4 and to some extent, FAC-013. CHPD believes the retirement of FAC-010-3 will not create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

System Operating Limits in the planning horizon in the Eastern Interconnection are generally the applicable steady-state ratings of the facilities, which are included in the powerflow models and are tested in a wide range of contingency analyses as required by standard TPL-001-4. Voltage limits are generally published in transmission planning criteria documents.	
Likes 0	
Dislikes 0	
Response	
There are considerable variations between different entities within the Eastern Interconnection and all other Interconnections in what is considered a planning SOL. This lack of consistency can be problematic when determining what limits to respect and it also speaks to the limited value the standard has.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We strongly support the retirement of FAC-010-3 and the SDT rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	

ATC agrees with the retirement of FAC-010-3 due to the proposed revisions to FAC-011 and FAC-014 as well as the creation of a proposed FAC-015-1 standard. These proposals adequately address the necessary coordination between operations and planning.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	2015-09_Unofficial_Comment_Form_092717_ERCOT_final.docx

Comment	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	
Document Name	
Comment	
MEAG Power supports all Southern Company responses herein. Scott Miller	
Likes 0	
Dislikes 0	

2. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.1 and R2.2, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Interpretation of Facility Ratings, System Voltage Limits and Stability limits are confusing and can be easily misinterpreted. In the background information above, SDT states that 'For example, "BES performance" for Facility Ratings is determined through OPAs and RTAs which assess the flow on Facilities in the pre- and post-Contingency states…' As it can be seen Facility Ratings can be interpreted as Thermal ratings only. Facility Ratings should include both Thermal ratings and voltage ratings of the equipment.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with your point, and allows facility owners to include in the voltage limits considered when System Voltage Limits are developed any Facility Rating based voltage limits for the facilities in question. This has been noted in the rationale document.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

Commentary and Support: In the existing FAC-011-3 paradigm, System Operating Limits (SOLs) are essentially the means used to limit the system so that the Bulk Electric System (BES) has acceptable performance both pre-contingency and post-contingency. Although not a term used in FAC-011-3, the concept of 'Reliable Operation' from the NERC Glossary of Terms is helpful in describing the objective:

Reliable Operation: "Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits…"

In the new, proposed FAC-011-4 paradigm, the focus is removed from SOLs as the tool to ensure secure system operations, and instead moves to assessing whether expected operating conditions are within acceptable performance pre- and post-contingency. If studies indicate otherwise, entities and the RC implement and utilize Operating Plans to keep the system within acceptable performance.

Conceptually, FAC-011-3 and FAC-011-4 are very similar. One uses SOLs to keep the system within acceptable performance; the other uses Operating Plans when unacceptable performance is identified. Therefore, the reliability objectives are maintained, although the terminology and approach has now changed.

In the description of the proposed FAC-011-4, SOLs now play a role similar to Facility Ratings, Voltage Criteria, and Stability Criteria; SOLs are now part of the criteria to assess acceptable BES performance via OPAs and RTAs.

Comment 1: CHPD would like to see an approach where the assessment of the system is started with Facility Ratings and performance criteria, and SOLs, if required, be used as an operational tool to support operating within those Facility Ratings and performance criteria, along with generation re-dispatch, topology re-configuration, etc.

Comment 2: Regarding the contingencies transferred from FAC-011-3 to FAC-011-4 to align with the TPL contingencies, there are two discontinuities worth mentioning.

In the old FAC-011-3, R2.2.2. listed "Loss of any generator, line, transformer, or shunt device without a Fault".

The new FAC-011-4 description is now "…or without a Fault: generator; transmission circuit; transformer; shunt device; or single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system."

In TPL-001-4, the analogous no-fault contingency is a category P2.1, and is described in TPL-001-4 Table 1 as "Opening of a line section w/o a fault".

In summary, the new FAC-011-4 adds the single pole block to the list of no-fault outages. This probably has minor impact, but CHPD is unsure why it is being added. The second change, which is maintained, is of greater mention – there has been a discontinuity between the TPL requirements for no-fault (line section w/o a fault) and both the old and new FAC-011 standards (generator, line (old) / transmission circuit (new) transformer, shunt device (or single pole block). This could mean that these non-fault events aren't planned for through TPL, but are expected to be operated to through the FAC standard. CHPD requests this be examined by the Standard Drafting Team to see if a better alignment between TPL and FAC can be arranged. Additionally, the difference between the old FAC-011-3 'line' and the new FAC-011-4 'transmission circuit' could be clarified if these are intended to be the same thing, or if differences are intended (and if so, what are those differences).	
Likes 0	
Dislikes 0	
Response	
The SDT did not create the concept of the use of SOLs when performing OPAs, real time monitoring and real time assessments. That was established with the current set of TOP standards, which became effective in April of 2017. The SDT is attempting, with the proposed changes, to bring the FAC standards, and the proposed definitions, into conformance with the existing practices in the current TOP standards. In addition, the SDT attempted, with this revision, to simplify and shorten portions of the existing standard. The language your later comments references was one of the revisions for contingencies created in the interest of efficiency. The SDT did not intend to add contingencies, and agreed that the consequences of no fault and fault induced loss of facilities are likely to be similar, with the fault induced variety usually the more severe. The no fault clause was added in the case that an entity rationalized that subject equipment could "not fault". A no fault loss case would then still be examined. The inclusion of these types of events was not to force examination of the added no fault cases when the responsible entity determined that a fault-induced version of the contingency was more sever. With that determination, the SDT reviewed your observation and determined that no further revision is warranted.	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	

With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.

Likes 0	
Dislikes 0	

Response

The SDT agrees with your comment and has included revisions in the proposed standards to make more explicit the fact that the RCs will only use ratings from those supplied by the transmission asset owners.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

We do not agree with the proposed definition of SOL Exceedance. In our proposed definition below, we excluded the criteria for which contingencies should be assessed. We do not believe that the state of the system (pre or post contingency) should be included in the definition of SOL Exceedance, but should be left outside that definition. We believe that an RC's SOL methodology should define the conditions in which an SOL should not be exceeded.

Southern's Proposed definition:

SOL Exceedance - An operating condition, as determined in Real-time Monitoring, where a System Operating Limit is exceeded.

An exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. Predicted exceedances, such as those identified through OPAs and RTAs, may or may not occur as they are just that, predicted. Predicted exceedances should not be defined and subject to the stringent set of limitations and requirements that SOL Exceedances should be. Furthermore, how predicted exceedances are identified, assessed, operationally planned for and mitigated should be

the responsibility of the Reliability Coordinator. Therefore, any such definition for predicted exceedances should remain in the respective RC's SOL methodology.	
Likes 0	
Dislikes 0	
Response	
The SDT is removing the proposed SOL Exceedance definition from its proposed FAC standards changes due to industry comments. Instead, we are including performance criteria in the proposed FAC 011-4 standard. The performance criteria specify acceptable pre and post contingent system performance, just as the current FAC-011-3 standard does.	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
The existing TOP standards adequately cover BES performance.	

Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
The language in Requirement 2: "for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations" needs work. Suggested language: "for Transmission Operators to determine SOLs based upon the Transmission Owner-provided Facility Ratings."	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with your comment and has included revisions in the proposed standards to make more explicit the fact that the RCs will only use ratings from those supplied by the transmission asset owners.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	

Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees that no reliability gap is introduced with the removal of the requirements R2, R2.1, and R2.2. Peak agrees with the justifications set forth in the FAC-011 mapping document for these requirements. Peak also believes that the removal of requirements R2, R2.1 and R2.2 would be strengthened by adoption of the proposed definition of SOL Exceedance.	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that these requirements should be removed from FAC-011-3 because they don't apply to the Operations Horizon.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of	

Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
NIPSCO is concerned that the requirement does not provide adequate assurance that the RC will respect the ratings established by the TO or the TO's FAC-008 methodology. As written, the language is vague and could be interpreted as allowing an RC to determine the ratings that a TOP must use (including normal and emergency ratings and seasonal changeover dates) without respecting the TO's authority to establish such Facility Ratings.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with your comment and has included revisions in the proposed standards to make more explicit the fact that the RCs will only use ratings from those supplied by the transmission asset owners.	

3. Given the background discussion and the justification provided in the mapping document for FAC-011-3, Requirement R2, R2.3 and R2.4, do you agree that BES performance is adequately covered and that no reliability gaps are introduced from the removal of those concepts in a revised FAC-011-4? If not, please explain specifically what aspects of the removal you disagree with and propose alternative language.

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP recommends retaining the clarifying language of 2.3 and 2.4. Having the options explicitly stated within the standard ensures consistency throughout each RC area in the way TOPs respond to Contingencies. Having those clear, well-defined options spelled out within the RC's SOL Methodology enhances reliability by setting consistent expectations of what actions neighboring or overlapping TOPs may be performing. Furthermore, it is valuable to house the language within a standard dealing with the Operations Planning Horizon, to avoid a potential misconception that the described options are only permissible when planning the system in the Near-term or Long-term Planning Horizons.

Likes 0	
Dislikes 0	

Response

The SDT discussed at length retention of the language or the concepts captured in the language. The end result of those efforts was a new proposed requirement in FAC-014-3, R8, that states:

In addressing any potential or actual SOL exceedances, each Reliability Coordinator and Transmission Operator shall allow for Non-Consequential Load Loss within their Operating Plan only if all other means of System adjustments have been exhausted to prevent: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

- *equipment damage, or*
- *instability, Cascading, uncontrolled separation*

We believe this requirement better describes the criteria under which Non-Consequential Load can be shed when operating the system.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	No
Document Name	
Comment	
See response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with your comment and has included revisions in the proposed standards to make more explicit the fact that the RCs will only use ratings from those supplied by the transmission asset owners.	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	
Likes 0	
Dislikes 0	
Response	

The SDT agrees with your comment and has included revisions in the proposed standards to make more explicit the fact that the RCs will only use ratings from those supplied by the transmission asset owners.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

Comment 1: CHPD is concerned about the 'permitted uses' language of RAS and other schemes, to be contained in the RC's methodology. In the TPL / Planning process, an entity may determine and build a scheme under a certain set of assumptions (how the system was planned / designed / built). The entity may determine this scheme is acceptable to their own operations. The RC may then prohibit the use of this non-RAS in the RC's SOL methodology, rendering the scheme useless for actual operations. CHPD has witnessed this concern with one of its neighbor's automatic schemes and feels that the prohibition of the scheme's use for operations has not always been in the best interest of system reliability. CHPD also recognizes the Planning Coordinator and Reliability Coordinator will be performing additional coordination through the new PRC-012-2, whose purpose is stated as "To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System

(BES)." The requirement here in FAC-011 may be duplicative of those objectives found in the new PRC-012-2.

In FAC-011-3, only allowed uses of Remedial Action Schemes was listed under the RC's methodology requirements. In FAC-011-4, the addition of 'other automatic post-Contingency mitigation actions' adds significant scope to the methodology. CHPD wants the Standard Drafting Team to ensure that the concept of 'operated as designed' is maintained in the use of these other automatic post-Contingency mitigation actions.

Comment 2: In the discussion about UFLS being not permitted in R4.6 (and by omittance, UVLS being permitted) CHPD identifies that there seems to be confusion, or at least the potential for confusion, about the FERC order and acceptable use or non-use of these schemes. The first point is that there is a difference between a UFLS or UVLS program. From the NERC glossary of terms:

Undervoltage Load Shedding Program: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Underfrequency Load Shedding Program is not described in the NERC glossary of terms, but is described in the purpose description for PRC-006: To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures A UFLS or UVLS program is a coordinated use of UFLS or UVLS relays at multiple locations and are essentially used to prevent described conditions that are essentially the events of an IROL. The FERC order 818 states regarding UVLS programs: “We conclude that UVLS **programs** (emphasis added) under PRC-010-1 are examples of such “safety nets” and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies.” Again, in the “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations”, on page 109 in the discussion about UFLS as a safety net, it simply states: Safety nets should not be relied upon to establish transfer limits CHPD would like clarification here in the proposed FAC-011-4 whether the references to UFLS (and UVLS) are meant to be to the UFLS (PRC-006) and UVLS (PRC-010) Programs or is it a reference to something else.

Likes 0	
Dislikes 0	

Response
The SDT reviewed your comment and gave careful consideration to your concern regarding "operate as designed". However, given our understanding that the RC is the highest operating authority, the SDT believes it is appropriate for the RC to document, in its SOL methodology, how RAS and other automatic schemes will be treated when determining stability limits. For example, an automatic under voltage load shed scheme could actuate during a stability simulation, which in turn could impact stability limits. The RC, in its SOL methodology, should be establishing the use practice for RAS that is then consistently used by all entities that determine stability limits. The SDT believes that if the RC has found that a RAS performs, based upon real-world experience, in some fashion other than as designed, then the RC has the responsibility to document how that RAS should be used when performing OPAs and RTAs.

The SDT has reviewed your comment with regard to UFLS and UVLS Programs and have included language revisions in FAC-011-4, Part 4.7, which were intended to provide clarity regarding allowed use of these schemes / programs.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees that BES performance is adequately covered and that no reliability gap is introduced with the removal of the requirements R2, R2.3 and its subparts, and R2.4. Peak agrees with the justifications set forth in the FAC-011 mapping document for these requirements. Peak believes that the “rules” set forth in the current FAC-011-3 R2, R2.3 and its subparts, and R2.4 have relevance in the TPL standards, but not in the TOP or IRO standards. When planners plan the system, they are constructing a system that meets the performance requirements set forth in TPL-001-4. This system is then provided to operators to operate. Rules such as those reflected in Table 1 of TPL-001-4 and the footnotes of Table 1 are important for identifying Corrective Action Plans associated with determining how the system is to be built; however, Peak believes the “rules” as reflected in FAC-011-3 R2, R2.3 and its subparts, and R2.4 are not necessary for operating the system. Operators encounter many operating scenarios that were not addressed or anticipated in the TPL Planning Assessments, and very often these conditions are more severe than those assessed in the Planning Assessments. Peak agrees with the SDT’s assertion that operators need the flexibility to operate the	

system to address SOL exceedances without being confined to such "rules" regarding non-consequential load loss, interruption of firm transmission, and requirements associated with preparations for the next Contingency. All of these items are expected to be addressed as needed in associated Operating Plans. Accordingly, operators do not need to be confined to these "rules" set forth in current FAC-011-3 R2, R2.3 and its subparts, and R2.4.	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Duke Energy would like to point out to the SDT, a potential typo in the FAC-011-3 Mapping Document. When referencing the translation of R2 and its sub-requirements to a New Standard or Other Action, the SDT appears to reference a TOP-012-3 standard R14. We believe that this was in error, and that perhaps the drafting team meant to reference TOP-001-3 instead.	
Likes 0	
Dislikes 0	
Response	
The SDT would like to thank Duke Energy for the comment and we have corrected the reference.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	

We think the removal of BES performance from R2 is relevant, but that the performance requirements associated with determination of stability limits associated with SOLs are vague compared to the TPL assessments. Is the SDT intent to let full flexibility to the RC with regards to stability performance requirements per requirement 4.1? For example, is a unit pulling out of synchronism something up to the RC to demonstrate as acceptable for the purpose of determining SOLs/IROLs for a given interface?	
Likes 0	
Dislikes 0	
Response	
The SDT believes that since the RC is the highest operating authority, it has the right and responsibility to determine how stability assessments for determination of limits are to be performed. They have the flexibility to base those practices on anything, and could choose to do so based upon prevailing planning practice in the area, if appropriate and they chose to. With your specific example, it is the RC's responsibility to write into its SOL methodology how it wants unit stability treated. That treatment should account for existing standards and definitions, and, in this instance, not allow for a potential IROL (due to instability, Cascading or uncontrolled separation), for example.	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes

Document Name	
Comment	
The existing TOP standards adequately cover BES performance.	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of	

Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee
Likes 0
Dislikes 0
Response

4. Are there any reliability objectives of FAC-011-3, Requirement R2, R2.3 and R2.4 that you maintain need to be preserved in requirements relating to the development of Operating Plans which would reside outside the FAC family of standards? Please explain your response.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
As a practice, reliability objectives should be maintained in standards. Documentation and examples supporting those objectives (white papers, guidelines, etc.) can reside outside the standard. Regarding Operating Plans, the definition found in the NERC glossary of terms is sufficient for CHPD. Regarding R2, R2.3 and R2.4 as it deals with the response of the system to events, any other reliability objectives should be contained in the standard to ensure these items have the scrutiny, review, and due process related to these items. CHPD has mentioned some concerns in its responses to item #3, but has nothing in addition to those to add here.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
We support the ISO RTO Council Comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Peak believes that the “rules” set forth in the current FAC-011-3 R2, R2.3 and its subparts, and R2.4 have relevance in the TPL standards, but not in the TOP or IRO standards. When planners plan the system, they are constructing a system that meets the performance requirements set forth in TPL-001-4. This system is then provided to operators to operate. Rules such as those reflected in Table 1 of TPL-001-4 and the footnotes of Table 1 are important for identifying Corrective Action Plans associated with determining how the system is to be built; however, Peak believes the “rules” as reflected in FAC-011-3 R2, R2.3 and its subparts, and R2.4 are not necessary for operating the system. Operators encounter many operating scenarios that were not addressed or anticipated in the TPL Planning Assessments, and very often these conditions are more severe than those assessed in the Planning Assessments. Peak agrees with the SDT’s assertion that operators need the flexibility to operate the system to address SOL exceedances without being confined to such “rules” regarding non-consequential load loss, interruption of firm transmission, and requirements associated with preparations for the next Contingency. All of these items are expected to be addressed as needed in associated Operating Plans. Accordingly, operators do not need to be confined to these “rules” set forth in current FAC-011-3 R2, R2.3 and its subparts, and R2.4.-	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	
SRP Recommends retaining the language of R2.3 and R2.4 within the FAC-011-4 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Due to the majority of industry supporting the SDT's position that FAC-011-3, Requirement R2, R2.3 and R2.4 do not need to be preserved in FAC-011 or other standards, the SDT is proposing to not specifically preserve as the intended reliability objectives are either unnecessary or addressed with the new IRO/TOP standard revisions.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation supports the changes to the requirements because no gaps were identified as the result of the changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
BPA has reviewed R2, R2.3 and 2.4 and believes the TOP-001-4 and TOP-002-4 requirements are sufficient.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
The revised TOP and TPL standards cover the planning and operations of the system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gladys DeLaO - CPS Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
James Grimshaw - CPS Energy - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Thank you for your response.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your response.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments. Additional comment for consideration: Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition could be revised to state "Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded".	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Due to industry concern on the proposed SOL Exceedance definition, the SDT has modified FAC-011-4 to include a new proposed requirement R6 that preserves system performance criteria similar to current FAC-011-3 R2.1 and R2.2 and not proposing a new SOL exceedance definition.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We think actions allowed in real-time operations should not be part of FAC-011, but captured by TOP/IRO standards. We think there is ambiguity and a lack of consistency in the industry around allowed system adjustments and preparation for the next contingency (old R2.4) with refers indirectly to N-1-1 situations. Although it is clear that FAC-011 requires, at a minimum, to consider a set of single contingencies to address stability limits, it is not clear at all what are the minimum requirements applicable if the contingency was to occur… and how “preparing for the next contingency” is addressed by the current standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Due to the majority of industry supporting the SDT’s position that FAC-011-3, Requirement R2, R2.3 and R2.4 do not need to be preserved in FAC-011 or other standards, the SDT is proposing to not specifically preserve as the intended reliability objectives are either unnecessary or addressed with the new IRO/TOP standard revisions. The SDT agrees that if clarity is needed, it would need to be addressed in the IRO/TOP standards and not in FAC-011.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

5. Do you agree that the SDT should allow the use of UVLS in the establishment of stability limits? If not, please explain and provide alternative language.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
It is unclear in 4.6 (and the entirety of R4) if "stability limits" refers to either or both of the following (1) bulk transfer across the BES (transfer limit stability studies) or (2) load areas (local area limit stability studies). BPA believes that it is important to distinguish between transfer limit stability studies and local area limit stability studies. We recommend that the SDT add language to R4 to clarify that R4 applies to only transfer limit stability studies. BPA believes that the SDT should not allow UVLS in transfer limit stability studies, unless it is part of a designated RAS. We understand that FERC is describing transfer limit stability studies in Order 818. BPA therefore does not think that relying on UVLS, except where included in RAS, to increase transfer limits is appropriate. However, BPA believes that the SDT should allow UVLS in local area limit stability studies when failure of the UVLS would not result in cascading. If UVLS is not allowed in local area limit stability studies, the TOP may be forced to perform pre-contingency load shed. Proposed: Planned use of UFLS or UVLS in establishment of stability limits is not allowed unless either of the following conditions is true: Pre-contingency load shedding would be required in order to meet BES performance criteria Load shedding is already included as part of an approved Remedial Action Scheme	
Likes 0	
Dislikes 0	
Response	
The SDT believes that FERC order 818 directive is to never allow planned use of UFLS programs in the establishment of stability limited with no exception allowed the planned use of UVLS, it is important to note that the SDT believes that UVLS Program is different than the UVLS.	

The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
UVLS is a safety net. It should not be used as an acceptable tool to preserve acceptable system performance for credible contingencies unless it is part of a RAS. This is directly implied in FERC order 818. The wording should be: "R4.6 Describe…; neither the planned use of underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) is allowed in the establishment of stability limits."	
Likes 0	
Dislikes 0	
Response	
The SDT respectfully disagree with the reading of FERC order 818. The SDT believes that while FERC order 818 does explicitly prevent the utilization of UFLS and UVLS Program under the normal operation, the FERC order itself is silent in the utilization of UVLS that is not part of a UVLS Program the planned use of UVLS, it is important to note that the SDT believes that UVLS Program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

Reclamation has concerns with possible misinterpretation of FAC-011-4 R4.2 and R5 as it implies Real-Time Assessments will include Stability. Reclamation also does not agree with the identified single Contingency and multiple Contingencies for use in determining stability limits because the TOP will inform the RC which Contingencies are credible.	
Likes 0	
Dislikes 0	
Response	
R4.2 establishes a requirement to ensure that stability limits are established to meet the criteria set forth in 4.1 while R5 requires the RC methodology to describe the how contingencies are identified for use in Real-Time Assessments (RTAs). Both requirements are related to the establishment of stability limits which may or may not be a part of RTAs. It	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
UVLS is a safety net. It should not be used as an acceptable tool to preserve acceptable system performance for credible contingencies unless it is part of a RAS. This is directly implied in FERC order 818. The wording should be: “R4.6 Describe…; neither the planned use of underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) is allowed in the establishment of stability limits.”	
Likes 0	
Dislikes 0	
Response	
With regards to the planned use of UVLS, it is important to note that the SDT believes that UVLS Program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS program. For this reason,	

the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
UVLS should remain a safety net and not be relied upon to provide acceptable system performance even for N-1-1 or N-2 contingencies.	
Likes 0	
Dislikes 0	
Response	
With regards to the planned use of UVLS, it is important to note that the SDT believes that UVLS Program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") does not agree that the SDT should allow the use of UVLS in the establishment of stability limits. CenterPoint Energy believes that UVLS, like UFLS, is a "safety net" that is deployed as a preservation measure to maintain the reliability of the BES. UVLS should not be relied upon to establish limits in a planning environment, regardless of horizon.	

Likes 0	
Dislikes 0	
Response	
With regards to the planned use of UVLS, it is important to note that the SDT believes that UVLS program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
We support the ISO RTO Council Comments.	
Likes 0	
Dislikes 0	
Response	
See response to ISO RTO Council	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

These comments are duplicated from comments made on question #3 above. CHPD would note that the language stated in the NERC summary from the 2003 report uses the term ‘transfer limits’, whereas in this SOL revision document it is described as ‘stability limits’. These two terms have different meanings, and the reference in the SOL document should be reviewed.

In the discussion about UFLS being not permitted in R4.6 (and by omittance, UVLS being permitted) CHPD identifies that there seems to be confusion, or at least the potential for confusion, about the FERC order and acceptable use or non-use of these schemes. The first point is that there is a difference between a UFLS or UVLS program. From the NERC glossary of terms:

Undervoltage Load Shedding Program: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Underfrequency Load Shedding Program is not described in the NERC glossary of terms, but is described in the purpose description for PRC-006:

To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures

A UFLS or UVLS program is a coordinated use of UFLS or UVLS relays at multiple locations and are essentially used to prevent described conditions that are essentially the events of an IROL. The FERC order 818 states regarding UVLS programs:

“We conclude that UVLS **programs** (emphasis added) under PRC-010-1 are examples of such “safety nets” and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies.”

Again, in the “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations”, on page 109 in the discussion about UFLS as a safety net, it simply states:

Safety nets should not be relied upon to establish transfer limits

CHPD would like clarification here in the proposed FAC-011-4 whether the references to UFLS (and UVLS) are meant to be to the UFLS (PRC-006) and UVLS (PRC-010) Programs or is it a reference to something else.

Likes 0	
Dislikes 0	
Response	
The SDT believes that UVLS Program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS program. The SDT intent is to allow each RC to specific in its methodology treatment and allowance of UVLS in calculation of stability limit. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
UVLS should remain a safety net and not be relied upon to provide acceptable system performance even for N-1-1 or N-2 contingencies.	
Likes 0	
Dislikes 0	
Response	
With regards to the planned use of UVLS, it is important to note that the SDT believes that UVLS program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No

Document Name	
Comment	
We agree with FERC, Undervoltage load-shedding schemes (UVLS) are a "safety net" and should not be a tool used by Bulk Electric System operators in the derivation of stability limits. In some areas single contingencies include bus faults, stuck breakers and tower-contingencies. Note: ERCOT does not support this response.	
Likes 0	
Dislikes 0	
Response	
The SDT respectfully disagree with the reading of FERC order 818. The SDT believes that while FERC order 818 does explicitly prevent the utilization of UFLS and UVLS Program, the FERC order itself is silent in the utilization of UVLS that is not part of a UVLS Program. It is important to note that the SDT believes that UVLS program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	No
Document Name	
Comment	

Not sure how the SDT like entities to vote. The SDT rationale indicated that their understanding of FERC Order 818 prohibited the use UVLS in the establishment of stability limits for N-1 contingency. Hence, if the SDT understanding of the FERC order is correct that FERC doesn't allow use of UVLS in the establishment of stability limits for N-1 contingency then it would also mean that using UVLS is also prohibited for N-2 contingencies. Indicating a "Yes" to Question 5 is contradicted to FERC Order 818. Indicating a "No" to Question 5 is in alignment with the SDT understanding of FERC Order 818.	
Likes 0	
Dislikes 0	
Response	
The SDT believes that while FERC order 818 does explicitly prevent the utilization of UFLS and UVLS Program under normal operation, the FERC order itself is silent in the utilization of a UVLS that is not part of a UVLS Program. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the allowed use of UVLS assuming that its meaning is not restricted to the defined term UVLS Program and is used as an umbrella term that also includes local UVLS schemes. We would disagree if UVLS was intended to be synonymous with UVLS Program, since it would imply that use of local UVLS is not allowed. This illustrates the need to clarify what is the intended scope of UVLS in this standard.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with Xcel Energy. It is important to note that the SDT believes that UVLS Program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
A stability limit may arise due to any type of multiple contingency (R5.3 and R5.4). UVLS should be a permissible mitigation method to either eliminate or increase stability limits such that transfers are not unduly constrained.	
Likes 0	

Dislikes 0	
Response	
The SDT believes that it is best and more appropriate to allow each RC to document in its methodology when planned use of UVLS is allowed in the establishment of a stability limit. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Consistency is necessary between the mitigating actions permitted to maintain acceptable performance after N-1-1 and N-2 Contingencies in the Planning Assessment and Real-time Operations. The use of equal more limiting parameters prescribed in FAC-015-1 R1-R3 would be undermined by the prohibition of UVLS in response to more severe Contingencies when calculating SOLs.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with SRP and believes that it is best and more appropriate to allow each RC to document in its methodology when planned use of UVLS is allowed in the establishment of a stability limit. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	

Peak agrees that UVLS should be allowed for use to prevent adverse reliability impacts for Contingencies more severe than single P1 Contingencies and that such allowances should be addressed in the RC's SOL Methodology. However, Peak is concerned that the use of UVLS, RAS, and other automatic post-Contingency mitigation schemes are confined to the development of stability limits. Peak believes that the allowed use of RAS or other automatic post-Contingency mitigation actions should be extended beyond the establishment of stability limits to also apply to the development of Operating Plans in general. Because the current FAC-011-3 intermingles "how to operate the system" with SOL establishment, it can be argued that the current FAC-011-3 already allows the RC's SOL Methodology to extended beyond the establishment of stability limits to also apply to the development of Operating Plans. While Peak is supportive of the SDT's attempt to focus FAC-011-4 more on establishing Facility Ratings, System Voltage Limits, and stability limits used in operations and removing the aspects of FAC-011-3 that relate more to "how to operate the system", it seems the SDT inadvertently introduced an inconsistency by limiting the use of RAS (or automatic actions) for deriving stability limits only. Peak believes the RC should have the ability to determine the use of RAS and other automatic post-Contingency mitigation actions across the board – not just for stability limit establishment. This issue, however, does not seem appropriate to be addressed in the FAC family of standards.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with Peak and believes that it is best and more appropriate to allow each RC to document in its methodology when planned use of UVLS is allowed in the establishment of a stability limit. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Given that FERC Order 818 clearly addresses the prohibition of using UVLS for calculating SOLs for single N-1 Contingencies, the SDT should consider a footnote within FAC-011-4 Part 4.6 that recognizes the FERC Order 818's prohibition on the use of UVLS in the determination of N-1 stability limits.

Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response

The SDT believes that while FERC order 818 does explicitly prevent the utilization of UFLS and UVLS Program under normal operation, the FERC order itself is silent in the utilization of UVLS that is not part of UVLS Programs. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting NPCC comments

Likes 0	
Dislikes 0	

Response

Please see respond to NPCC

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities,

1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA appreciates the SDTs efforts to provide the background and historical context of UVLS and the derivation of IROLS. Unfortunately the background information provided is confusing and does not make clear what the SDT is trying convey. The rational appears to try and draw a line between UFLS and UVLS when in fact they perform the same function, but for different quantities. The use of UFLS is allowed in certain PC studied events and we see no reason why UFLS shouldn't be used where appropriate. We agree that UVLS should be considered in the establishment of stability limits; however we also believe UFLS should be allowed under certain scenarios as it is in the planning horizon.	
Likes 0	
Dislikes 0	
Response	
The SDT believes that FERC order 818 does explicitly prevent the utilization of UFLS and UVLS Program for any planned normal operations, the FERC order itself is silent in the utilization of UVLS that is not part of a UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Programs under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

UVLS is allowed to maintain system performance for some contingency events as described in Table 1 of standard TPL-001-4. The RC allowed use of UVLS should not conflict with standard TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with Ameren and believes that it is best and more appropriate to allow each RC to document in its methodology when planned use of UVLS is allowed in the establishment of a stability limit. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Programs under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
We agree with the allowed use of UVLS under certain conditions, but we strongly disagree with the way the SDT has addressed the allowed use of UFLS and UVLS in the new FAC-011. Since R5 gives some flexibility to the RC to choose its method for considering various types of contingencies (N-1, N-2, etc.) for both OPA/RTA and stability limits, the acceptable actions in R4.6 should not be limited as they can vary a lot depending on the types of contingencies considered. For example, a RC considering only the minimum single contingencies from R5.1 may not be allowed to use UFLS and UVLS actions for N-1… but another RC may choose to establish stability limits and limit transfers accordingly to address more stringent and rare multiple contingencies for which additional means like the action of UFLS/UVLS may be allowed (if that same RC would choose not to plan a stability limit for those contingencies, it would be acceptable to use UFLS/UVLS as a safety net?). Similarly, the reference to UVLS in SVL requirement R2 is not adequate, as SVL may comprise multiple levels, some for acceptable for single contingencies (without UVLS), some with some UVLS actions allowed for multiple contingencies. We think that the consequence of the action (e.g. the use of non-consequential load loss as in TPL) should be used throughout the standards to allow the use of actions for specific contingencies (rather than referring to RAS, UFLS or UVLS).	

Likes 0	
Dislikes 0	
Response	
The SDT is not contemplating allowance of UFLS. The SDT believes that it is best and more appropriate to allow each RC to document in its methodology when planned use of UVLS is allowed in the establishment of stability limit because UVLS is more localized in nature. It is important to note that the intent is to address UVLS and not UVLS Program as described in PRC-010 technical guideline.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
In the case of non-IROL SOLs we agree. However, it was noted that according to the background information above and in FAC-11-4, the use of UVLS is only considered in the context of establishing stability limits as per Requirement R4 Part 4.6. The use of UVLS should also be acceptable to respect Facility Ratings and System Voltage Limits.	
Likes 0	
Dislikes 0	
Response	
It is important to note that the intent is to address UVLS and not UVLS Program as described in PRC-010 technical guideline. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Program under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	

National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
See response to the NPCC's comment	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
The establishment of stability limits must take into account automatic actions, including RAS and UVLS, since the loss of load can negatively impact system and unit stability performance. The SDT is correct in including this language in the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with ATC	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT asserts it is not appropriate to use UVLS for the purpose of increasing transfer capability for stability limits for N-1 Contingencies. However, it may be appropriate to use UVLS to determine the post-contingency impact in regards to establishment of an IROL vs. an SOL. It may also be appropriate to use UVLS in determining whether or not pre-contingency load shedding is warranted.	
Likes 0	
Dislikes 0	
Response	
With regards to the planned use of UVLS, it is important to note that the SDT believes that UVLS program is different than the UVLS. The Technical guideline in PRC-010 shows an example of UVLS system that would not fall under the definition of UVLS Program. For this reason, the SDT has modified R4.7 to ensure prohibition of UVLS Programs under normal operation, but allow the RC methodology to specify if and when utilization of localized UVLS in operating horizon is acceptable.	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
See comment to ISO/RTO Council	

6. If you have any other comments that you haven't already provided in response to questions 2-5, please provide them here.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT suggests rewording proposed R2 to clarify that the SOL methodology establishes a method for determining which of the Facility Ratings provided by the owner should be used in operations, and not a method for establishing Facility Ratings. Please see the suggested language below.

"R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ***which of the*** applicable owner-provided Facility Ratings ***are*** to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

With respect to R3.5, the meaning of the phrase "Address the use of" is unclear. The meaning of this phrase could be interpreted several different ways. ERCOT understands that the intent of the SDT is to ensure that, under the SOL methodology, the RC and its TOPs have a method to determine how the common set of System Voltage Limits between the RC and TOPs are to be used in operations, without becoming overly prescriptive in the requirement language. ERCOT suggests rewording proposed R3.5 to "Address how the Reliability Coordinator and its Transmission Operators use common System Voltage Limits in the Reliability Coordinator Area;"

ERCOT notes that parts 4.1.1.-4.1.4. of R4 list the *minimum* stability performance criteria that should be used in the method to determine stability limits in operations. To add clarity, ERCOT suggests adding a new part 4.1.5 that reads ***"other stability performance criteria as required by the RC's SOL Methodology."***

****Please refer to the attached comment form for redlined language.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. With regards to your suggestions regarding use of a common set of Facility Ratings and/or System Voltage Limits, the SDT has adjusted the proposed language in FAC-011-4 R2 and R3.5 to clarify the intent of the requirement. The TOP and its RC should be using a common set of Facility Ratings and System Voltage Limits. gives the RC The SDT feels that the current "at a minimum" language around R4.1 for stability performance criteria is sufficient to allow the RC to specify other stability performance criteria in the RC SOL Methodology if the RC chooses to do so. The SDT felt adding the language as suggested in your comment may give entities the impression that requirement is implying additional stability performance criterion must be included	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
Requirement R7 of the proposed FAC-011-4 standard requires the RC to define the method and periodicity a TOP must communicate their SOLs back to the RC. In comparison, parts 5.3-5.5 of requirement R5 of FAC-014-3 identify such communications must occur on a mutually agreed upon time frame. We believe Requirement R7 should be changed to a mutually agreeable timeframe that reflects the frequency a Transmission Operator will conduct its Operational Planning Analyses and Real-time Assessments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT feels that it would be ideal for the TOP and RC to mutually agree on a timeframe for the TOP to provide SOLs to its RC. However, given that the RC has the authority to determine the timeframe at which it requires the TOP to provide its SOLs from its TOP, the SDT prefers the current language.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to NPCC RSC Group comments.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	
Document Name	
Comment	
ATC has the following concerns with the proposed FAC-011-4 standard. R3.1: Requirement R3.1 contains the term "stations" and uses an unconventional designation of "buses/stations". The NERC BES definition does not require entities to identify BES stations, which would make it problematic to use the requirement as written.	

Additionally, "buses/stations" is an unclear designation where entities may understand that System Voltage Limits shall be created for all Facilities in a station, including both BES and non-BES Facilities in that station. We do not believe this is the intent of the SDT so this should be clarified.

Consider modifying R3.1 language to state "Require that BES buses have an associated System Voltage Limit except for the BES buses that may be excluded as specified in the [RC]'s SOL methodology."

R3.2: Clarify R3.2, similar to R2 language, that "respect[ing] the Facility voltage Ratings" means determining the "applicable owner-provided Facility" voltage "Ratings to be used in operations". FAC-008-3 R2 and R3, in conjunction with the NERC "Facility Ratings" definition, requires the Generator Owners and Transmission Owners, respectively, to have voltage ratings for Facilities.

R4.5 and a New R5.5: Requirements R4.2, R4.4, R4.5 and R5 become applicable to all TOPs through proposed FAC-014-3 R2.

Given the language of R4.4, which requires "instability risks" to be "identified", ATC believes the standard overreaches at R5 when it includes stability analysis within OPAs and RTAs as determined by the RC. TOP-001-3 R13 and R14 and TOP-002-4 R1 already require the TOP study SOLs in RTAs and OPAs, and inclusion of OPAs and RTAs in R5 is redundant with TOP-001-3 and TOP-002-4. The TOPs are the local experts on the stability of their systems and the R5 requirement language should not force additional stability analysis beyond TOP-001-3 and TOP-002-4 in the OPA and RTA on to a TOP if stability is not an issue for its system. ATC recommends striking “and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs).” from R5.

A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read:

"R5.5 The applicability of the identified single Contingency and multiple Contingencies to its TOPs for use in determining stability limits."

Similarly, given the applicability of the model requirements stated in R4.5 to the TOPs performing stability studies under the RC SOL methodology, through FAC-014-3 R2, clarify is needed that a TOP does not need to have a model of similar scale or scope as the RC will use. Per TOP-003-3, TOPs determine what data is needed to perform their OPAs and RTAs and the scope of this data is likely a subset of the RC's data, whether covered by IRO-010-2 or proposed FAC-011-4 R4.5. The revision should make it clear that the breadth of the RC's model does not necessarily need to be replicated by the TOP.

A proposed revision to R4.5 to address this concern would be the addition of the following language to the current proposed R4.5 language:

"… necessary to determine different types of stability limits, including applicability of the model detail to studies performed by its TOPs"

New R4.x: The RC SOL methodology should include how "impacted" PCs and TOPs will be identified for stability SOLs. The "impacted" language appears in FAC-014-3 R4 and R5 and clarity is needed for all parties.

R7: The second sentence of R7 should be struck as it is a redundant requirement to IRO-010-2 R1. SOL communication should be a part of the RC's data specification, which already contains a requirement regarding periodicity of communication.

R8: The requirement should contain a minimum notice provision to TOPs, such as "30 days prior to implementation". The current language would permit an RC to issue a revision the day prior to a material change in its SOL methodology, possibly impacting a TOP's compliance under FAC-014.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

With regards to your suggestion for FAC-011-4 R3.1, the SDT has chosen to keep the reference to “buses/stations” as proposed. The SDT feels that it is necessary to clearly identify both stations and buses to ensure those who monitor station based limits (more often referenced by system operators) and those who are monitoring bus based limits (more typically referenced in power flow study groups) relate to this requirement.

With regards to your suggestion related to proposed FAC-011-R3, subpart 3.2, the SDT has attempted to remove confusion regarding the use of the term “voltage ratings” by adopting the phrase “voltage-based Facility Ratings” instead.

In response to the comment on FAC-11-4 R4.5, the SDT feels the language in the requirement R4.5 is clear as stated and works well with requirement R2 in FAC-014-3. The extent of an RC's area that needs to be modelled as part of TOP stability studies may vary depending on how widespread the stability phenomenon is, how large their footprint is within the RC's area, and what responsibility they've agreed to with their RC in performing those studies. Therefore, this type of clarification is better left to the RC's SOL Methodology rather than prescribed in the FAC-11-4 R4.5requirement. Furthermore, it was not the SDT's intent to imply a stability assessment must be run in all OPA and RTAs. Rather, it was intended that stability assessments must be performed considering, at a minimum, those contingencies in R5.1. Separately, and as indicated in R5, the SDT intended all contingencies specified in R5.1 to be run, at a minimum, as part of OPA and RTA, which may or may not include a stability assessment (if proven unnecessary due to prior studies). Though the SDT recommends the TOP and RC come to a mutual decision on the contingency set used in OPA and RTA and for stability assessments, the ultimate authority must rest with the RC and these decisions should be reflected in the RC's methodology. Regarding your comment on FAC-11-4 R7, the SDT feels that it is important to include the periodicity in the SOL Methodology for provision of SOL data. IRO-10-2 R1 speaks to periodicity of receipt of data necessary for OPA and RTA which is not entirely redundant. Given the importance of timely provision of SOLs from the TOP to RC, the SDT feels that providing this guidance in R7 in addition to IRO-10-2 is beneficial. The SDT agrees with your proposal for requirement R8 in FAC-011-4, such that a period of at least 30 days be given to those entities in receipt of the RC's methodology, to complete any implementation as a result of changes to the RC's methodology. The proposed requirement R8 has been updated to reflect this change.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	
Comment	

None.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	

This standard in its current form allows a single entity the ability to dictate operating and effectively planning criteria. PNM believes that the development of the SOL methodology should be a joint effort including RCs, TOPs, and PAs.

Propose revised R1 language: Each Reliability Coordinator, in conjunction with each of its Transmission Operations and Planning Coordinators, shall develop a methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area.

PNM believes that R2 gives the RC the ability to dictate how an entity uses its own Facility Ratings effectively modifying FAC-008. There is no point for an entity to establish a Facility rating that cannot be used when operating the system. PNM recommends removal of R2 and revision of FAC-008-3 to address any concerns regarding a lack of common facility ratings methodology.

PNM questions the reliability basis for R3.3. PNM believes that there may be legit reasons to have the UVLS settings higher than the limits for certain critical contingencies. FERC order No. 818 specifies not using UVLS for N-1; however, this requirement doesn't have that qualifier. If the SDT feels this concept should be included in the standard the requirement should move under R4.6 and shall clearly specify that it is only applicable to single contingencies.

PNM finds no difference between R6.1 and R6.2.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
With regards to your suggestion for FAC-11-4 R1, the SDT agrees with principal of the RC developing its SOL methodology in conjunction with those who are impacted by it. However, the RC needs to have the final authority in order carry out its responsibilities.
With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this.
With regards to your suggestion for FAC-011-4 R3.3, the SDT has modified the proposed language to make it clear that System Voltage Limits should be greater than or equal to UVLS scheme and/or program set points. This requirement is important to ensure that RCs and TOPs are aware of what their UVLS set points are and operate in the interest of avoiding load shed where possible.

FAC-11-4 requirements R6.1 and R6.2 have identical wording to existing requirements R1.3 and R3.7 from current standard, FAC-011-3. FAC-11-3 IROL requirement related issues will be examined for revision following the MEITFs efforts. Thank you for noting this.

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

FAC-11-4, Requirement R3.3 should be clear that it's only pre-contingency System Voltage Limits which should be above in-service UVLS scheme settings. When depending on these schemes, a post-contingency System Voltage Limit may fall below a UVLS set point.

FAC-11-4 Requirement R3 Part R3.4 should either be revised or removed. Identifying the lowest allowable System Voltage Limit does not make sense from the context of minimum voltage SVLs (it should be the highest SVL identified). Perhaps "lowest" could be replaced by "most restrictive".

Where FAC-11-4 Requirement R3 Part 3.7 requires coordination between adjacent RCs for SVLs the FAC-11-4 Requirement R2 and R4 are silent on this with respect to Facility Ratings and stability limits. The RC should also be coordinating Facility Rating and Stability SOL actions with RCs within an Interconnection where applicable and this should be spelled out in FAC-11-4.

FAC-11-4 Requirement R4.1.2 should not force Reliability Coordinators into adopting transient voltage response criteria as part of their SOL Methodology. There are effective alternative means to guard against coincidental load loss and inadvertent tripping such as employing a relay margin criterion instead. Please remove or modify the requirement to recognize viable alternatives exist.

FAC-11-4 Requirement R4.1.2 should not force Reliability Coordinators into adopting transient voltage response criteria as part of their SOL Methodology. Transient voltage criterion results should be communicated to the Reliability Coordinator as outlined in FAC-15-1 Requirement R6 for consideration.

FAC-11-4 Requirement R4.1.3 introduces the term “angular stability”. Why is System damping considered separately? Angular stability consists of Transient Stability and Small Signal Stability, System damping would be part of Small Signal Stability.

FAC-11-4 Requirement R4.4 appears to ask for so much detail in the SOL Methodology (FAC-11-4 Rationale indicates enough information should be provided to duplicate the study) that it would be extremely onerous to satisfy given that the assumptions made for each operating zone of our RC area are vastly different given the common conditions and risks that exist. Detailed assumptions around instability risks, transfer levels, dispatch and system conditions are better left in study documentation pertaining to each specific zone. (Also see 5 below. We believe that there is value in sharing SOLs and associated study reports based on need/request.)

Additionally, the phrase “instability risks are identified” is misleading and does not really contribute to the objective of the requirement/standard. We assess that the intent of R4 is to present the method for determining stability limit, not to identify risks although they are the driver for developing stability limit. If the intent of that phrase is to present the stability concerns and/or the way to address such concerns through SOL determination, then we offer the following revised wording:

“Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and the applicable System conditions including any changes to System topology such as Facility outages;”

FAC-11-4 Requirement R4.5 asks for a description of the critical details from other Reliability Coordinator areas necessary to determine stability limits. This is in conflict with FAC-14-3 R5 which no longer enforces that Reliability Coordinators *provide its SOLs and IROLs to*

those entities with a reliability need. IRO-014-3 speaks to required information for Operating Plans, Procedures and Processes but does not address the need for critical details required for developing SOLs. Furthermore, obtaining these critical details from other Reliability Coordinators and verifying their impact to SOLs through study can require a great deal of time and effort. It is recommended that more than 12 months be given in order to comply with this requirement. An appropriate time would be in the order of 24 – 36 months. Obtaining these critical details would also be made much easier and the information would be much more valuable if all Reliability Coordinators (RC) were aligned in respecting the same set of contingencies and performance criterion for IROLs. For example, if an RC finds an instability issue due to a multiple contingency in a neighboring RC's footprint there's no requirement in FAC-11 and FAC-14 that supports forcing the neighbor to respect that contingency in the interest of interconnected system reliably as multiple contingencies are still left up to the RC's discretion. FAC-11-4 Requirement R5.2 leaves the door open for any potential contingency to be considered credible and will create an unnecessary burden in attempting to show compliance. Listing other specific single contingencies that could be deemed credible would improve this requirement. An alternative to listing additional specific contingencies would be to revert to the existing language in FAC-11-3 Requirement R2.2 which specifies, at a minimum, which contingencies must be respected. FAC-11-4 Requirement R6.2 is redundant with Requirement R6.1 in that a criterion is what is used to identify SOLs that are IROLs. Consider revising to combine the two sub-requirements to remove unnecessary duplication and confusion. FAC-11-4 Requirement R8 requires RCs to provision of their SOL Methodology to other entities. Given that the changes to the FAC-11-4 standard require substantial documentation work on the part of many RCs, more time should be given for compliance. At least 36 months is recommended. Furthermore, given there will be changes coming to the IROL requirements in this very same standard maybe the compliance period should be extended to the compliance deadline associated with that version of the FAC-11 standard to avoid the burden of duplicating a great deal of work.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. With regards to your suggestion for FAC-011-4 R3.3, the SDT has modified the proposed language to make it clear that System Voltage Limits should be greater than or equal to UVLS scheme and/or program set points. This requirement is important to ensure that RCs and TOPs are aware of what their UVLS set points are and operate in the interest of avoiding load shed where possible. With regards to your suggestion for FAC-011-4 R3.4, the SDT believes the proposed language is adequate. The intent of this requirement is to have the RC establish the lowest allowable System Voltage Limit for their RC area such that TOPs do not establish System Voltage Limits below that threshold. Ensuring coordinated setting of System Voltage Limits with other TOPs is essential for Reliable Operation in the RC's footprint. With regards to your suggestions regarding use of a common set of Facility Ratings and/or System Voltage Limits, the SDT has adjusted the proposed language in FAC-011-4 R2 and R3.5 to clarify the intent of the requirement. The TOP and its RC should be using a common set of Facility Ratings and System Voltage Limits. In response to your suggestion on forcing adoption of a transient voltage response criterion as per FAC-11-4 R4.1.2, the team feels strongly that one should be adopted by all RCs as it helps ensure reliability as facilities are able to stay connected during a fault if not directly connected to the faulted equipment. Though other methods may be used to approximate this, the SDT felt this is the most accurate industry-common approach to achieving this performance. The SDT agrees with the suggested wording to replace "instability risks are identified" in FAC-11-4 R4.4 for improved clarity and has made the revision. Thank you. The term "angular stability" in FAC-11-4 R4.1.3 was used to ensure transient voltage response and system damping criteria could be called out specifically to ensure industry would understand a criteria for system damping is required in the RC's methodology. In response to the comment regarding FAC-11-4 R4.5, the SDT believes description of details around studies performed in other RC areas is (or should be more specifically) addressed in the IRO-014 standard discussing RC-to-RC communication.

Requirement 5.2 of FAC-11-4 was designed to give the RC the authority to include additional contingencies, given their risk to the system as part of stability assessments, OPAs and/or RTAs. Though the SDT recommends the TOP and RC (and perhaps other entities) make this determination together, the RC has the ultimate authority on the matter. The SDT believes this an important requirement to maintain.

FAC-11-4 requirements R6.1 and R6.2 have identical wording to existing requirements R1.3 and R3.7 from current standard, FAC-011-3. FAC-11-3 IROL requirement related issues will be examined for revision following the MEITFs efforts. Thank you for noting this.

The SDT recognizes the need for more time to be given to entities to comply with the changes to the FAC-011-4 standard and recommends a period of 18 months from the time of applicability.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	

FAC-011-4 Requirement R2 specifically states that the RC "shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations". It goes on to identify that the method "shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area". This requirement needs to be bounded such that the RC is not specifying in its methodology how a Transmission Operator and thus a Transmission Owner is required to rate its transmission facilities, up to and including the use of real time ratings. This would determine the amount of risk a Transmission Owner is subject to for its facilities. The standard should only specify the end objective and not the process to achieve that objective.

FAC-011-4 Requirement R3.2 introduces the concept of "Facility voltage Ratings". This is not a defined term and leaves room for interpretation. There is no standard that requires TO's to provide Facility Ratings for voltage. Before TOP's are required to operate to Facility Ratings for voltage there should be a requirement for TO's to provide Facility Ratings for voltage.

FAC-011-4 Requirement R4 seems to be somewhat duplicative of TPL-001-4 requirements R5 and R6. Consideration should be given to coordination of these requirements.

FAC-011-4 Requirement R5 includes language that requires the RC's SOL Methodology to include "the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPA's) and Real-time Assessments (RTA's)". Use of SOL's in OPA's and RTA's is covered in TOP-001 and TOP-002. The concept of requiring how SOL's should be used in OPA's and RTA's should be removed from this requirement. FAC-011-4 R7 is redundant with IRO-010-2 R1. As the SDT notes in its preface to FAC-011-4, SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R7 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.

Likes 0	
Dislikes 0	

Response
With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. In response to your comment for FAC-011-4 R5, the intent of the requirement to have "the method for identifying contingencies for use….." was to be different from the TOP requirement to describe how SOL's should be used. The method for identifying contingencies for use in OPA/RTAs is specific to how to come up with which contingencies should be selected to determine SOLs; whereas, it's understood that "how SOLs are used…" is about the selection of the SOLs themselves as inputs to the OPA/RTA. Regarding your comment on FAC-11-4 R7, the SDT feels that it is important to include the periodicity in the SOL Methodology for provision of SOL data. IRO-10-2 R1 speaks to periodicity of receipt of data necessary for OPA and RTA which is not entirely redundant. Given the importance of timely provision of SOLs from the TOP to RC, the SDT feels that providing this guidance in R7 in addition to IRO-10-2 is beneficial.

Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	

FAC-011 R3.1

We do not agree with Part 3.1 as written since it implies that all BES (i.e. each and every) buses/stations within an RC or TOP area need to have a SVL. To meet this requirement, an RC/TOP will need to determine and list a large number of System Voltage Limits (SVLs), many of which have no impact on the BES voltage performance and hence serve little or no value to the determination of SOLs and/or IROLs.

The proposed definition of SVL is:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

With this definition, we interpret that there may be more than one SVL within an RC or TOP area, and that the identified SVLs are the limiting parameters with which to assess acceptable voltage performance on an RC or TOP system and their interconnected systems. An RC or TOP may identify a handful of buses/stations within their areas to be requiring the stipulation of SVLs, while deeming it unnecessary to stipulate SVLs on other buses/stations as acceptable voltage performance can be assessed/assured by observing the stipulated SVLs.

We therefore suggest Part 3.1 be reworded as follows:

R3.1. Require the identification of the critical BES buses/stations and associated System Voltage Limits with which to assess acceptable System performance

FAC-011 R3.2

This part is not required. Observing the more restrictive of the two – SVLs and Facility voltage Ratings, is the general practice for any RCs and TOPs. If the SDT wish to spell out this requirement explicitly, we propose the following wording:

3.2 Require that the more restrictive of the System Voltage Limits and the Facility voltage Ratings at the same bus/station be respected.

FAC-011 R3.4

This part is not required since all applicable SVLs (may be more than one) identified in the proposed Part 3.1 will be observed in the determination of SOLs. Identifying the lowest allowable SVL serves little or no purpose, or can be insufficient, in the determination of SOLs.

We suggest deleting Part 3.4

FAC-011 R3.5,6,7

The overall intent of these parts is to ensure the methodology specifies the use of common SVLs by those entities that need to determine SOLs around those buses/stations for which SVLs are identified. This can be achieved by combining them into the following proposed part:

3.5. Address the use of common System Voltage Limits by all entities in the Reliability Coordinator Area and the process to coordinate the determination of System Voltage Limits between neighboring Reliability Coordinators and Transmission Operators.

FAC-011 R4.4

The phrase "instability risks are identified" is misleading and does not really contribute to the objective of the requirement/standard. We assess that the intent of R4 is to present the method for determining stability limit, not to identify risks although they are the driver for developing stability limit. If the intent of that phrase is to present the stability concerns and/or the way to address such concerns through SOL determination, then we offer the following revised wording:

4.4 Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and the applicable System conditions including any changes to System topology such as Facility outages;

FAC-011 R5

We interpret R5 to require identification of relevant single Contingencies AND multiple Contingencies for use in determining stability limits, and in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs), and any Planning Coordinator identified contingency events for use in determining stability limits. As such, and considering the umbrella wording in R5 and that Parts 5.1 to 5.3 essentially cover all contingency events, we do not see the need for Parts 5.1, 5.2 and 5.3. To add clarity, we propose R5 be revised, to include Part 5.4, as follows:

R5 Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits, and in performing Operational Plans Analyses (OPAs) and Real-time Assessments (RTAs), and the method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement R6 to identify the Contingencies for use in determining stability limits.

Note: ERCOT does not support the response to Q6

Likes 0	
Dislikes 0	

Response

With regards to your suggestion for FAC-011-4 R3.1, the SDT has chosen to keep the reference to “buses/stations” as proposed. The SDT feels that it is necessary to clearly identify both stations and buses to ensure those who monitor station based limits (more often referenced by system operators) and those who are monitoring bus based limits (more typically referenced in power flow study groups) relate to this requirement. In addition, the term “System” is capitalized in the definition such that only BES equipment should have an associated System Voltage Limit unless an exclusion in made. The SDT contends the proposed language in FAC-011-4 R3.1 allows for the flexibility in setting System Voltage Limits you’ve suggested in your comments and proposed revision.

With regards to your suggestion related to proposed FAC-011-R3, subpart 3.2, the SDT has attempted to remove confusion regarding the use of the term “voltage ratings” by adopting the phrase “voltage based Facility Ratings” instead.

With regards to your suggestion for FAC-011-4 R3.4, the SDT believes the proposed language is adequate. The intent of this requirement is to have the RC establish the lowest allowable System Voltage Limit for their RC area such that TOPs do not establish System Voltage Limits below that threshold. Ensuring coordinated setting of System Voltage Limits with other TOPs is essential for Reliable Operation in the RC’s footprint.

With regards to your suggestions regarding use of a common set of Facility Ratings and/or System Voltage Limits, the SDT has adjusted the proposed language in FAC-011-4 R2 and R3.5 to clarify the intent of the requirement. The TOP and its RC should be using a common set of Facility Ratings and System Voltage Limits. The SDT agrees with the suggested wording to replace "instability risks are identified" in FAC-11-4 R4.4 for improved clarity and has made the revision. Thank you. In response to your suggestion for FAC-11-4 R5 rewording to consider an umbrella requirement for single and multiple contingencies, the SDT feels that it's important to distinguish the minimum set and types of contingencies that must be respected. This ensures clarity on specifically which contingencies must be a part of stability assessments, OPAs and RTAs. Therefore, the current language has been maintained in R5.1 with some small adjustments to the remaining subparts.

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	

Answer	
Document Name	
Comment	

1- We support the harmonization and approach to the new standards for the establishment of SOLs. However, we do have an important concern regarding the way the use of UVLS and UFLS in the establishment of stability limits was incorporated in the FAC-011-4 requirements. Although the requirements give good flexibility to the RC in identifying the set of contingencies applicable for SOL determination, they also impose performance requirements (SVLs and limited use of UFLS/UVLS) that do not make any distinction between the mandatory single contingencies and the complimentary multiple contingencies. Since the RC has flexibility to identify the relevant contingencies beyond the minimum requirements from R5.1.1, it should also have flexibility in the performance requirements for the allowed use of mitigation actions.

2- We think the level of description in sub-requirements R3.X for System Voltage Limits is a burden without added benefit to reliability. Why so much details for SVL and not for Facility Ratings? R3.5-3.7 are not needed. If coordination is an issue, it should be addressed in a single requirement for the whole standard. R3.2 is redundant with the application of FR in R2. R3.3 is an issue that should be addressed with the allowed used of UVLS under certain circumstances, not captured by SVL requirements. Different SVLs may be used for different contingencies, not just N-1. R3.4 is redundant with SVL definition.

3- R4.2 is a redundant cross-reference with 4.1 and R5 and does not bring any benefit to the remaining of the standard. R4.3 also is redundant since the RC has to describe how stability limits are established per R4 whether or not multiple TOPs are involved.

4- Concerning the selection of contingencies, it is understood that the RC has full flexibility to determine the appropriate multiple contingencies for its System, correct? If that is the case, the proposed standard should allow the same flexibility for the performance requirements associated with those contingencies, namely the use of UVLS and UFLS.

5- Although we appreciate the standard’s flexibility regarding the stability performance requirements in R4.1, there seems to be a lack of guidelines and minimum expected performance as in TPL (no mention of Cascading, instability, etc.).

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. With regards to your suggestion for FAC-011-4 R3.3, the SDT has modified the proposed language to make it clear that System Voltage Limits should be greater than or equal to UVLS scheme and/or program set points. This requirement is important to ensure that RCs and TOPs are aware of what their UVLS set points are and operate in the interest of avoiding load shed where possible. With regards to your suggestions regarding use of a common set of Facility Ratings and/or System Voltage Limits, the SDT has adjusted the proposed language in FAC-011-4 R2 and R3.5 to clarify the intent of the requirement. The TOP and its RC should be using a common set of Facility Ratings and System Voltage Limits.

Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

Comment 1: It is a common concept in industry that the system should be operated as it is planned. The TPL-001-4 standard is one of the main regulatory drivers to the planning of the system, while the FAC standards regarding SOLs are important to the operation. While not possible to align the two standards entirely, there are some features of the TPL standard which may have merit for the FAC-011 standard revision which have not been addressed in the draft of the proposed revision of FAC-011-4. These include:

Voltage Criteria (TPL-001-4 R5)

Instability Criteria (TPL-001-4 R6)

Division of responsibilities (TPL-001-4 R7)

The Voltage criteria is present in both FAC-011-3 and TPL-001-4. While TPL-001-4 voltage criteria requirement includes steady state, post-contingency deviation, and transient voltage response, the proposed FAC-011-3 criteria has additional performance metrics. This presents a risk where the system may not be operated as it was planned, because the criteria proposed in FAC-014-3 could be more conservative than the criteria required by TPL-001-4. The Standard Drafting Team should take this opportunity to consider aligning the operational criteria in the proposed FAC-011-3 with that of TPL-001-4. CHPD recognizes that due to the variety of unknowns encountered in real-time, operational criteria should have more flexibility than system planning.

Comment 2: CHPD is also concerned by the requirements in R3.6. and R3.7. regarding coordination of these system limits. This is not well addressed in the Standard Drafting Material as to the intent and scope of the proposed coordination. If the expectation is simply to share, post, or distribute limits, then that would be a helpful clarification. If the expectation is to conduct additional coordination studies involving multiple parties and the RC, then it is clearly a greater body of work and should be addressed further and clarified by the Standard Drafting Team as to the nature of these expectations.

CHPD is in favor of the removal of R3.6. and R3.7. altogether, because the coordination of these is already essentially performed through the use of the OPA and RTA.

Comment 3: The continued use of margins in FAC-011-4 (also found in FAC-011-3) is another instance of mis-alignment between TPL-001-4 and FAC-011-3. CHPD recognizes that there is value to include an assessment of margin in the operational realm, but is also aware that this is a difference in the way the system is planned vs. operated, and in some instances may result in the system being operated to support a particular margin that wasn't necessarily planned through TPL-001-4 or other planning standards. CHPD recognizes that due to the variety of unknowns encountered in real-time, operational criteria should have more flexibility than system planning.

Comment 4: Regarding the voltage criteria proposed in FAC-011-4 R4, there are a number of concerns.

The use of the term 'steady-state voltage stability' in 4.1.1. is confusing. Steady state analysis is different than stability analysis. Please clarify this term. If this is the feature described in the 2003 blackout report, this would be the assessment of reactive power support.

Angular stability criteria is a new metric to the FAC-011 standard; this concept is discussed to some extent in the 2003 blackout report as well. It is assumed that this is the analog to the FAC-011-3 requirement R1.2.4 "The system demonstrates *transient*, *dynamic*, and voltage stability" (emphasis added). CHPD would prefer the transient and dynamic language from FAC-011-3 to be maintained, rather than 'angular'. The system damping criteria in 4.1.4. and the transient voltage response in 4.1.2 could be also included as part of the angular (transient/dynamic) criteria, and does not need to be specifically enumerated.

If the Standard Drafting Team feels prescriptive requirements are required over performance based requirements, CHPD believes that this requirement could be simplified to something similar to "The Reliability Coordinator shall have voltage reactive margin criteria" and "The Reliability Coordinator shall have stability criteria for a) transient voltage response, and b) system damping"

Comment 5: CHPD would also like to see a requirement for a definition of System Instability in the RC SOL methodology, analogous to the TPL-001-4 R6:

TPL-001-4 R6: "Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

CHPD finds the text of TPL-001-4 R6 adequate to incorporate into the proposed FAC-011-4, with the Transmission Planner and Planning Coordinator references updated to Reliability Coordinator. This is particularly important since the Reliability Coordinator is to identify IROLs, which are these types of system phenomena.

Comment 6: Requirement in FAC-011-3 R3.4 – "Identify the lowest allowable System Voltage Limit;" seems duplicative or redundant to the proposed definition of System Voltage Limit – "The maximum and ***minimum*** steady-state voltage limits (both normal and emergency) that provide for acceptable System performance."

The System Voltage Limit, in itself, should be the minimum allowable system voltage.

Comment 7: There is no mention of steady state thermal performance in the requirements for the Reliability Coordinator SOL methodology, nor language stating that SOLs shall not exceed associated Facility Ratings for thermal ratings (as found in the old FAC-010-3 R1.2). CHPD strongly encourages the Standards Drafting Team to add language supporting the operation within thermal limits to the proposed FAC-011-4 document, possibly in the vicinity of R4, which discusses stability and voltage criteria.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

With regards to your suggestion for FAC-011-4 R3.4, the SDT believes the proposed language is adequate. The intent of this requirement is to have the RC establish the lowest allowable System Voltage Limit for their RC area such that TOPs do not establish System Voltage Limits below that threshold. Ensuring coordinated setting of System Voltage Limits with other TOPs is essential for Reliable Operation in the RC's footprint.

With regards to your suggestions regarding use of a common set of Facility Ratings and/or System Voltage Limits, the SDT has adjusted the proposed language in FAC-011-4 R2 and R3.5 to clarify the intent of the requirement. The TOP and its RC should be using a common set of Facility Ratings and System Voltage Limits. In response to your comment regarding the use of the term "steady-state voltage instability" in FAC-11-4 R4.1.1, the SDT felt it was important to distinguish between voltage stability criteria applied in steady-state analysis vs. voltage stability criteria applications in dynamics, namely "transient voltage response" to ensure both criteria are included in the RC's SOL Methodology. The SDT felt steady-state voltage stability was a commonly used term in industry to describe the use of steady-state analysis conducted in the interest of determining voltage based stability limits that are, as you've stated, the result of a lack of reactive power support. Similarly, the term "angular stability" was used to ensure transient voltage response and system damping criteria could be called out specifically.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	
Comment	
It is unclear by the wording of R4 whether Transmission Operators determine stability limits or the RC. Based on R2 and R3, it is clear that the Transmission Operators develop Facility Ratings and System Voltage Limits based on the RC methodology. Based on R7, it says SOLs are communicated to the RC. One can assume this includes the stability limits as well, but R4 could be spelled out as a TOP task to develop stability limits (unless the door is intentionally being left open for the RC to determine stability limits in parallel to the TOP). It should be the TOP developing all of the SOLs and communicating them to the RC. The RC should only drive the methodology and determine which of the provided SOLs qualify as IROLs.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	

FMPA recommends a feedback loop be introduced to FAC-011-4 for the RC's SOL methodology, such as found in FAC-008-3 R5. This will provide for better coordination between the PC and the RC, improve the effectiveness of the RC's Stability assessment, and allow consideration of best Stability analysis practices within the RC's footprint.

It is not clear what the phrase "for use in performing OPAs and RTAs" as used in R5 is intending. Are just the RC's OPAs and RTAs required to use this list of contingencies, or are all entities performing OPAs and RTAs within the RC footprint required to use this list? It does not make sense for every TOP to use the same extensive list of contingencies, since they may not have a need to model the System beyond their immediate TOP area.

Additionally, as currently worded R5 requires Stability analysis to be run on all contingencies that qualify as P1 events under TPL-001-4, which would result in a tremendous amount of work, but very little beneficial insight. The ability to apply engineering judgement to select those events that are expected to result in more severe System impacts is needed.

FMPA sees the use of the term "normal clearing" (lowercase, but note that the capitalized, defined term is used in the bulleted list) in 5.1.1 as problematic. Breaker failure schemes meet both the definition of Delayed Fault Clearing and the definition of Normal Clearing as they are currently written. Is it the SDT's intent to require breaker failure be included when determining stability limits? If not, FMPA recommends changing "with normal clearing" to "without Delayed Fault Clearing".

Likes 0	
Dislikes 0	
Response	

Thank you for your comments.

The intent of the requirements around contingencies FAC-11-4 R5 is to have the method for prescribing how the contingency list(s) used in stability assessments, OPAs and RTAs. These lists could all be different depending on how widespread a stability phenomenon is, how large their footprint is within the RC's area, and what responsibility they've agreed to with their RC in performing those studies etc.

Furthermore, it was not the SDT's intent to imply a stability assessment must be run in all OPA and RTAs. Rather, it was intended that stability assessments must be performed considering, at a minimum, those contingencies in R5.1. Separately, and as indicated in R5, the SDT intended all contingencies specified in R5.1 to be run, at a minimum, as part of OPA and RTA, which may or may not include a stability assessment (if proven unnecessary due to prior studies). Though the SDT recommends the TOP and RC come to a mutual decision on the contingency set used in OPA and RTA and for stability assessments, the ultimate authority must rest with the RC and these decisions should be reflected in the RC's methodology.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP Standard Review Group has a concern in reference to the drafting team intents for Requirement R2. From our perspective, this proposed language may suggest that the RC will receive the authority to tell the Transmission Owner how to determine their Facility Ratings. We would ask that the drafting team provides more clarity on the intent for this Requirement.

The SPP Standard Review Group has a concern that the drafting team has potentially created a new term by adding the term "voltage" between Facility Ratings. We recommend that the drafting team uses the proposed phrase "voltage Facility Ratings**."**

The SPP Standards Review Group has a concern that the drafting team may have caused confusion by not including the actual FAC-011-3 Standard in the posted material. From our perspective, this creates an inconsistency and disconnection on what the drafting teams intents

are for this project. For future reference, we would suggest the drafting team include all pertinent documentation to help provide clarity and demonstrate consistency on what their intents and goals are for the project. The SPP Standards Review Group has a concern pertaining to the language in Requirement 6 Subpart 6.2. There is a confusion on which term “violating” or “Exceedance” should be used in the Subpart language. From our perspective, the drafting team has put a lot of emphasis on the term “Exceedance” as they have developed a definition for the term “SOL Exceedance” and we feel that the term “Exceedance” should be referenced in the language to promote consistency with the intents of the drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. FAC-11-4 requirements R6.1 and R6.2 have identical wording to existing requirements R1.3 and R3.7 from current standard, FAC-011-3. FAC-11-3 IROL requirement related issues will be examined for revision following the MEITFs efforts. Thank you for noting this.	
Sean Erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
The language in Requirement R3 Part 3.2 that refers to “Facility voltage Ratings” is problematic. Splitting a NERC-defined term (Facility Ratings) with voltage isn’t a good practice. Suggested language: “the maximum and minimum voltage Facility Ratings”.	

WAPA has a concern regarding the wording for **FAC-011-4 R4** and **R5** and the linkage between**.**

As written R4 implies **required** Stability assessments in all OPAs and RTAs.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

{C}**4.1.** ….

{C}**4.2.** Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for

identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include:

WAPA understands that was not the intent of the SDT and suggests this minor modification:

4.2. Require that ***identified*** stability limits meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 ***for OPAs and RTAs***. **(Or)**

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. And remove stability from the body of R5 and add a R5.5 (as initially suggested by the MRO-NSRF with WAPA's modification)

A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read: "R5.5 The applicability of the identified single Contingency and multiple Contingencies **as agreed to by** its TOPs for use in determining stability limits."

Lastly, it appears "additional" is missing from Requirement 5.3

5.3. Any ***additional*** types of multiple Contingency events identified for use in determining

stability limits, or for use in performing OPAs and RTAs. Without it, R5.3 is redundant to the body of R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. With regards to your suggestion related to proposed FAC-011-R3, subpart 3.2, the SDT has attempted to remove confusion regarding the use of the term "voltage ratings" by adopting the phrase "voltage based facility ratings" instead. In response to your comment regarding FAC-11-4 R4 and R5, it was not the SDT's intent to imply a stability assessment must be run in all OPA and RTAs. Rather, it was intended that stability assessments must be performed considering, at a minimum, those contingencies in R5.1. Separately, and as indicated in R5, the SDT intended all contingencies specified in R5.1 to be run, at a minimum, as part of OPA and RTA, which may or may not include a stability assessment (if proven unnecessary due to prior studies).	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections: Violation Severity Levels Requirement 8 VSL	

The VSL for Requirement R8 references Part 8.4 but there is no Part 8.4 in the standard. ReliabilityFirst believes that the timing piece is now incorporated into the main R8 Requirement and suggest the reference to Part 8.4 be removed from the VSL	
Likes 0	
Dislikes 0	
Response	
Thank you for bringing this to attention. The SDT has amended FAC-011-4 requirement R8.4 as a result.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to NPCC comments.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	
Document Name	
Comment	
We support the ISO RTO Council Comments.	

Likes 0	
Dislikes 0	
Response	
Thank you. Please see the response to ISO RTO comments.	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	

Likes 0	
Dislikes 0	
Response	
With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this.	
Scott Downey - Peak Reliability - 1	
Answer	
Document Name	
Comment	
Peak believes that requirement R5 should contain a subpart that requires the RC's SOL Methodology to include a description of the performance requirements for Contingencies more severe than the single Contingencies listed in part 5.1.1. In operations, the operating criteria for single Contingencies is often more stringent than that of more severe Contingencies such as breaker failure Contingencies or common structure Contingencies. Accordingly, some RC's only examine these more sever Contingencies for instability, Cascading, or uncontrolled separation, and they may not screen such severe Contingencies for thermal or voltage exceedances as described in the proposed definition of SOL Exceedance. The SDT could include a subpart 5.5 which states, "The minimum performance requirements for Contingencies more severe than those described in subpart 5.1.1."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Performance requirements for single and multiple contingencies are identified through imposing the requirements in FAC-11-4 R2, R3 R4 in conjunction with the proposed SOL Exceedance definition. These requirements give the RC the latitude to impose a different set of	

requirements for more severe contingencies if they so choose. Creating a requirement for minimum performance of more severe contingencies may increase reliable operation to some degree but could also tie the hands of some entities that may not have the infrastructure to operate and reliably server customers to respect such severe contingencies which are usually much less likely to occur.

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

With regard to the proposed Requirement R2, CenterPoint Energy believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. CenterPoint suggests the following language for the proposed Requirement R2:

“Each Reliability Coordinator shall include in its SOL Methodology a mutually agreeable method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.”

With regard to the proposed Requirement R6.2, the existing legacy language uses the word “violating” in reference to an exceedance of an SOL that qualifies as an IROL. CenterPoint Energy recommends the SDT revise the wording so that there is no negative connotation to the context of the proposed requirement.

CenterPoint Energy suggests the following language for the proposed Requirement R6.2:

“R6.2 Criteria for determining when an SOL exceedance qualifies as an IROL and criteria for developing any associated IROL TV.”

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. FAC-11-4 requirements R6.1 and R6.2 have identical wording to existing requirements R1.3 and R3.7 from current standard, FAC-011-3. FAC-11-3 IROL requirement related issues will be examined for revision following the MEITFs efforts. Thank you for noting this.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	
Not directly related to questions 2-5, the NERC SAR related to Project 2015-09 identified the need "to address the issues identified in the FAC PRRs related to the application of the IROL term." The proposed FAC-011-4 does not appear to have addressed the consistent application of IROL and simply maintains the language from FAC-011-3.	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

SRP appreciates the efforts of the SDT and supports how the proposed changes generally reduce redundancy and provide clarity in communications. The SDT has also made improvements in further linking the planning and operational limits. SRP also has some recommendations for the SDT: In FAC-011-4 R1, SRP recommends retaining the phrase "documented methodology". In FAC-011-4 4.4, SRP recommends requiring a process for acknowledgement of new/changing stability limits by operational personnel.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Regarding your suggestion for FAC-011-4 R1, the SDT agrees that it's required that the methodology be documented and has thus chosen to retain the phrase as you've suggested.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. – 3	
Answer	
Document Name	
Comment	
With regard to the proposed Requirement R2, OGE believes that the proposed language could be mistakenly interpreted as giving the Reliability Coordinator the discretion to impose unacceptable Facility Ratings to Transmission Operators. We would ask that the drafting team provides more clarity on the intent for this requirement.	
Likes 1	Tay Sing On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5;
Dislikes 0	
Response	

With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this.	
John Seelke - LS Power Transmission, LLC – 1	
Answer	
Document Name	v4 LSPT Q7 attachment SOL, SOL Exceedance comments.docx
Comment	
LSPT previously provided informal comments regarding the definition of "SOL Exceedance." In response to question 7, separate attached comments proposed changes to R6 of proposed FAC-011-4 that are related to recommended changes in the SDT's proposed SOL Exceedance definition. Those separate comments are attached to this question. Numbered paragraph 5 explains the recommended changes to R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see comments related to SOL Exceedance.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	
R4.6 specifically does not allow the use of UFLS in the establishment of stability limits, which is acceptable for all single contingencies and multiple contingencies as define by P1-P7 events in Table 1 of TPL-001-4. However, R5.4 requires consideration of contingency events by the PC in R6 of FAC-015-1. It could be that the Planning Assessment identified Cascading following an extreme event even with UFLS included. It's	

unclear whether the RC will consider this a valid stability limit or not. There should be limits placed on the scope of R6 of FAC-015-1 to P1-P7 events to allow the exclusion in R4.6 to remain.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT feels that this decision is up to the RC given that this contingency is extreme and beyond those required to be respected as per the proposed FAC-011-4 requirements. There are times when, unexpectedly, extreme events may become a relevant risk to system reliability and warrant SOLs be put in place to respect them. For this reason the SDT feels that the requirement should not preclude the RC from recognizing extreme events relying on safety nets such as UFLS.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
The intent of Proposed R2 needs more clarification as to which entities are using the same rating, for example: RC & TOP? or RC & all TOPs for the same facility? Is the intent to have all TOP's under the same RC using the same ratings methodology? The intent of Proposed R5.4 is unclear. We believe the Planning Coordinator should provide the established stability limit and the method by which the RC should assess the system against established stability limits. Maybe an example would help the understanding. Proposed R8.1 needs to define under what circumstances a nonadjacent Reliability Coordinator would have a reliability-related need for the Reliability Coordinator's SOL Methodology.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT agrees with your suggestion and FAC-011-4 R2 has been modified accordingly. With regards to your comment on FAC-11-4 R5.4, the intent of this requirement is to have the RC's methodology describe how to identify which of the contingency events provided by the Planning Coordinator (PC) will be considered to determine stability limits in Operations. Unless the PC is the entity responsible for determining stability limits using performance criterion used in Operations, the RC or TOP will need to study the particular contingency using performance criterion for Operations to create a System Operating Limits (SOL) suitable for use in OPAs and RTAs. With regards to your comment on FAC-011-4 requirement R8.1, the SDT feels this language should be maintained. RCs may require SOL Methodology updates from non-adjacent RCs where the impact of contingency events may reach across another RC's footprint into their footprint or conditions in non-adjacent footprints may impact transfer limits in a non-adjacent RC's area.

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	
Document Name	
Comment	
While we agree with the changes to FAC-011, we will be voting "No" because of our problems with FAC-015. These changes to FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reworked a number of requirements in the proposed FAC-015-1 to satisfy concerns raised in balloting.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	
Document Name	
Comment	

The first sentence of FAC-011-4 R2 should be clarified as follows: “Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are applicable that are to be used in operations.” The proposed clarification makes it more obvious that the SOL Methodology only determines which owner-provided ratings are applicable for use in operations.

FAC-011-4 R3.1: Requirement R3.1 contains the term "stations" and uses an unconventional designation of "buses/stations."

- The NERC BES definition does not require entities to identify BES stations, which would make it problematic to use the requirement as written.
- Additionally, "buses/stations" is an unclear designation where entities may understand that System Voltage Limits shall be created for all Facilities in a station, including both BES and non-BES Facilities in that station. We do not believe this is the intent of the SDT so this should be clarified.
- Consider modifying R3.1 language to state "Require that BES buses have an associated System Voltage Limit except for the BES buses that may be excluded as specified in the RC's SOL methodology."

R4.5 and a new R5.5: Requirements R4.2, R4.4, R4.5, and R5 become applicable to all TOPs through proposed FAC-014-3 R2.

- Given the language of R4.4, which requires "instability risks" to be "identified," ATC believes the standard overreaches at R5 when it includes stability analysis within OPAs and RTAs as determined by the RC. TOP-001-3 R13 and R14 and TOP-002-4 R1 already require the TOP study SOLs in RTAs and OPAs, and inclusion of OPAs and RTAs in R5 is redundant with TOP-001-3 and TOP-002-4. The TOPs are the local experts on the stability of their systems and the R5 requirement language should not force additional stability analysis beyond TOP-001-3 and TOP-002-4 in the OPA and RTA on to a TOP if stability is not an issue for its system. ATC recommends striking “and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)” from R5.

A proposed revision to R5 to address this concern is the addition of a new requirement R5.5, which would read: "R5.5 The applicability of the identified single Contingency and multiple Contingencies to its TOPs for use in determining stability limits."

Similarly, given the applicability of the model requirements stated in R4.5 to the TOPs performing stability studies under the RC SOL methodology, through FAC-014-3 R2, clarity is needed that a TOP does not need to have a model of similar scale or scope as the RC will use. Per TOP-003-3, TOPs determine what data is needed to perform their OPAs and RTAs and the scope of this data is likely a subset of the RC's data, whether covered by IRO-010-2 or proposed FAC-011-4 R4.5. The revision should make it clear that the breadth of the RC's model does not necessarily need to be replicated by the TOP.

A proposed revision to R4.5 to address this concern would be the addition of the following language to the current proposed R4.5 language: "… necessary to determine different types of stability limits, including applicability of the model detail to studies performed by its TOPs."

FAC-011-4 R3.2: the term used is "Facility voltage Ratings." The defined term is "Facility Ratings." Remove voltage or reword to say "Facility Ratings for voltage."

FAC-011-4 R6.2: The term "violating" relates to previous Standard. Suggest: "Criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL Tv."

FAC-011-4 R7 is redundant with IRO-010-2 R1. As the SDT notes in its preface to FAC-011-4, SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R7 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.

FAC-011-4 R8 does not specify how far in advance of the effective date of the SOL Methodology the RC must provide its SOL Methodology to other entities. With other standard requirements that Transmission Operators develop their SOLs in accordance with the RCs SOL Methodology, changes that would require a new determination of SOLs based upon the new methodology could take some time to develop. It is recommended that the RC provide its methodology at least 30 days prior to the effective date to give entities an opportunity to evaluate changes to the methodology and implement any changes necessary to their SOLs prior to the effective date of the new SOL Methodology. Without sufficient time a registered entity could find themselves in violation of standard requirements due to lack of time to make changes to SOLs according to the new methodology.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments.
With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this.

With regards to your suggestion related to proposed FAC-011-R3, subpart 3.2, the SDT has attempted to remove confusion regarding the use of the term “voltage ratings” by adopting the phrase “voltage-based Facility Ratings” instead.

With regards to your suggestion for FAC-011-4 R3.1, the SDT has chosen to keep the reference to “buses/stations” as proposed. The SDT feels that it is necessary to clearly identify both stations and buses to ensure those who monitor station based limits (more often referenced by system operators) and those who are monitoring bus based limits (more typically referenced in power flow study groups) relate to this requirement.

In response to the comment on FAC-11-4 R4.5, the SDT feels the language in the requirement R4.5 is clear as stated and works well with requirement R2 in FAC-014-3. The extent of an RC’s area that needs to be modelled as part of TOP stability studies may vary depending on how widespread the stability phenomenon is, how large their footprint is within the RC’s area, and what responsibility they’ve agreed to with their RC in performing those studies. Therefore, this type of clarification is better left to the RC’s SOL Methodology rather than prescribed in the FAC-11-4 R4.5requirement.

Furthermore, it was not the SDT’s intent to imply a stability assessment must be run in all OPA and RTAs. Rather, it was intended that stability assessments must be performed considering, at a minimum, those contingencies in R5.1. Separately, and as indicated in R5, the SDT intended all contingencies specified in R5.1 to be run, at a minimum, as part of OPA and RTA, which may or may not include a stability assessment (if proven unnecessary due to prior studies). Though the SDT recommends the TOP and RC come to a mutual decision on the contingency set used in OPA and RTA and for stability assessments, the ultimate authority must rest with the RC and these decisions should be reflected in the RC’s methodology.

FAC-11-4 requirements R6.1 and R6.2 have identical wording to existing requirements R1.3 and R3.7 from current standard, FAC-011-3. FAC-11-3 IROL requirement related issues will be examined for revision following the MEITFs efforts. Thank you for noting this.

The SDT agrees with your proposal for requirement R8 in FAC-011-4, such that a period of at least 30 days be given to those entities in receipt of the RC's methodology, to complete any implementation as a result of changes to the RC's methodology. The proposed requirement R8 has been updated to reflect this change.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	
Document Name	
Comment	
LES is concerned that Requirement R2 does not provide adequate assurance that the Reliability Coordinator will respect the Facility Ratings established by the TO, or the TO's FAC-008 methodology. As written, the language is vague and appears to allow the RC to determine the Facility Ratings and voltage ratings that a TO must use. Additionally, based on the NERC definition of Facility Rating, there is a potential conflict between System Voltage Limits and Facility Ratings as both can utilize voltage ratings. At minimum, consideration should be given to potential inconsistencies that may develop between FAC-011-4, FAC-008-3 and the definition of Facility Rating as a result of the project.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. With regards to your suggestion related to proposed FAC-011-R3, subpart 3.2, the SDT has attempted to remove confusion regarding the use of the term “voltage ratings” by adopting the phrase “voltage-based Facility Ratings” instead.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
While we agree with the changes to FAC-011, we are voting “No” because of our concerns with FAC-015. These changes to FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reworked a number of requirements in the proposed FAC-015-1 to satisfy concerns raised in balloting.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	
Document Name	
Comment	
FAC-011-3 R2 and R3 add an additional translation layer on top of FAC-008 which already defines the determination of Facility Ratings. Could this additional translation allow for the RC to impose ratings and risk that the TO owning the facility is not willing to accept? An example is forcing the use of dynamic ratings. The language in R3.3 that requires the System Voltage Limit to be higher than the UVLS setting nullifies the ability to use local UVLS schemes. There exist local UVLS schemes that have been planned to operate at the emergency low voltage limit to protect local load and meet TPL requirements for prior outage (N-1-1) conditions. Effectively disallowing the use of local UVLS schemes to achieve acceptable system performance was likely not the intent. We suggest modifying the R3.3 language to address this unintended consequence. Requiring the operating limit to be more restrictive does not align with FAC-015 philosophy where the planning limits should be more restrictive.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

With regards to your suggestion for FAC-011-4 R2, the SDT agrees that the RC does not establish or dictate facility ratings for operations. Rather, the responsibility of the RC is to choose which of the applicable owner provided facility ratings are used to avoid conflicts between the RC and its TOPs during system operation. The SDT has chosen to modify the language in R2 to better reflect this. With regards to your suggestion for FAC-011-4 R3.3, the SDT has modified the proposed language to make it clear that System Voltage Limits should be greater than or equal to UVLS scheme and/or program set points. This requirement is important to ensure that RCs and TOPs are aware of what their UVLS set points are and operate in the interest of avoiding load shed where possible.

Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	
Response	

7. The SDT is proposing to divide existing Requirement R1 of FAC-014-2 into three requirements in FAC-014-3 to clearly indicate which entities have the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) [the RC], System Operating Limits (SOLs) [the TOP] and stability limits that impact more than one TOP in its Reliability Coordinator Area [the RC] into proposed Requirements R1, R2, and R4, respectively. Do you agree with the proposed changes? If not, please explain.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA supports R1 and R2. However, BPA does not agree with breaking out R4. It should be the impacted TOPs’ responsibility to coordinate, establish and agree upon the stability limits, not the RC’s.

Likes 0	
Dislikes 0	

Response

The RC is the highest level of authority in the operating horizon, as such, the RC should have the highest purview and wide-area understanding of the stability limit that impacts more than one TOP. The SDT believes that stability limits that impact more than one TOP should be supervised by the RC who has the wide-area responsibility.

A stability limit that impacts multiple TOPs could be found by the RC, it could be a discussion initiated by a TOP, or it could be the RC reviewing the TOP Stability limits and finding a common one. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC’s own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work.

The requirement places the ultimate responsibility on the RC to establish the limit, but by design does not specify how those limits are found or how the RC establishes them.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Xcel Energy feels that R2 should be expanded so that the RC has a role for SOLs that impact more than one TOP, similar to R4. The alternative would be for R4 to be expanded beyond "stability limit" to be more general SOL that impacts more than one TOP. An example would be an interface/path/flowgate that is thermal limited below its Facility Rating due to other thermal (or voltage) limited transmission facilities in multiple TOPs. This concern would likely be addressed if the revised SOL definition is approved and is effective simultaneously with the FAC standards - we recognize that the revised SOL definition makes it clear that the MW limit for an interface/path/flowgate is an SOL only if it is a stability limit.	
Likes 0	
Dislikes 0	
Response	
The SOL whitepaper approved by NERC noted that the SOL is based on the actual set of Facility Ratings, System Voltage Limits and stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices and mechanisms employed by that entity. An example would be the utilization of interface/path/flowgate that is thermal limited below its Facility Rating due to other thermal (or voltage) limited transmission facilities in multiple TOPs. The SDT believes R2 is sufficient and does not need to be expanded. This approach will provide sufficient flexibility without creating potential confusion on who has the responsibility to establish SOL.	

Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF is not convinced the RC's have the experience necessary to determine stability limits where the limits impact more than one TOP. Although it may make sense to designate the RC as responsible, historically this has been done by TOPs cooperating with each other to determine the limits. The concern is the RCs may not understand the nuances associated with all of their footprint.	
Likes 0	
Dislikes 0	
Response	
The RC is the highest level of authority in the operating horizon, as such, the RC should have the highest purview and wide-area understanding of the stability limit that impacts more than one TOP. The SDT believes that stability limits that impact more than one TOP should be supervised by the RC who has the wide-area responsibility. A stability limit that impacts multiple TOPs could be found by the RC, it could be a discussion initiated by a TOP, or it could be the RC reviewing the TOP Stability limits and finding a common one. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work. The requirement places the ultimate responsibility on the RC to establish the limit, but by design does not specify how those limits are found or how the RC establishes them.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	

Comment	
This is a helpful proposed clarification. However, in the definition of IROL from the NERC glossary an IROL is: "A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." Therefore, one must calculate what the SOL is first, before determining whether the SOL is an IROL. If the RC is not required to calculate SOLs, how will it be able to determine whether or not the SOLs are IROLs? CHPD would propose that both TOPs and the RC calculate SOLs, but only the RC has the duty to determine which SOLs are IROLs. This would be consistent with the current FAC-014-2 approach and ensure that the RC is calculating SOLs so it can identify which SOLs are IROLs. If the RC is not calculating SOLs, there is the potential risk that the RC could miss an SOL which should be classified as an IROL.	
Likes 0	
Dislikes 0	
Response	
All IROLs are SOLs. This requirement requires RC to establish IROLs. The RC methodology may utilize the two step process whereby an SOL is established first. The current requirement allows flexibility on how the RC establishes the IROL. The SDT believes that there does not need to be a "two steps" process.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment	
FMPA appreciates the desire to clearly indicate which entities have the responsibility for establishing SOLs and IROLs, but believes additional clarity in FAC-014-3 is needed. First, it is not clear who has the responsibility to run the stability studies, or how often to run them. Another concern is that IROLs, SOLs, and stability limits are not mutually exclusive. Are TOPs precluded from identifying IROLs?	
Likes 0	
Dislikes 0	
Response	
The SDT believes the ultimate responsibility to establish IROLs belongs to the RC. The potential instability, uncontrolled separation, or Cascading outages could be found by the RC or could be a discussion initiated by a TOP. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work. Requirement places the ultimate responsibility on the RC to establish and declare the IROL. This is important because there are other IRO Reliability Standard requirements that need to be coordinated by the RC.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	No
Document Name	
Comment	
We agree with R1 and R2, but we don't see the need to specifically require the RC to establish stability limits per R4 when more than one TOP is impacted. This should be addressed through the determination of SOL/IROLs per R1 and R2 in FAC-014 and the requirement that the methodology from FAC-011 include the method for determining stability limits. There is an unnecessary redundancy.	
Likes 0	

Dislikes 0	
Response	

The RC is the highest level of authority in the operating horizon, as such, the RC should have the highest purview and wide-area understanding of the stability limit that impacts more than one TOP. The SDT believes that stability limits that impact more than one TOP should be supervised by the RC who has the wide-area responsibility.

A stability limit that impacts multiple TOPs could be found by the RC, it could be a discussion initiated by a TOP, or it could be the RC reviewing the TOP Stability limits and finding a common one. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work.

The requirement places the ultimate responsibility on the RC to establish the limit, but by design does not specify how those limits are found or how the RC establishes them.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

Without stating requirements for performance criteria and assessment methodology for what SOLs qualify as an IROL, the roles of each entity in this matter remains unclear.

Likes 0	
Dislikes 0	
Response	

The requirements related to IROL are kept consistent with the current process. These requirements present clear role regardless the performance criteria. The requirement places the responsibility to TOP to establish SOL and places the responsibility to RC to establish IROL and stability limits that involve multiple TOPs.

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR agrees with R1 and R2 but proposes the following language for R4: Each Reliability Coordinator, in conjunction with the impacted Transmission Operators, shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	
Likes 0	
Dislikes 0	
Response	
The RC is the highest level of authority in the operating horizon, as such, the RC should have the highest purview and wide-area understanding of the stability limit that impacts more than one TOP. The SDT believes that stability limits that impact more than one TOP should be supervised by the RC who has the wide-area responsibility. A stability limit that impacts multiple TOPs could be found by the RC, it could be a discussion initiated by a TOP, or it could be the RC reviewing the TOP Stability limits and finding a common one. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC’s own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work. The requirement places the ultimate responsibility on the RC to establish the limit, but by design does not specify how those limits are found or how the RC establishes them.	

No modification was made to R4.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
ATC believes these changes are acceptable if the SDT adds a new requirement R4.x to FAC-011-4 as explained above in our comments to question #6 where we recommend a new requirement that requires the RC to identify how they will determine "impact[ed]" entities.	
Likes 0	
Dislikes 0	
Response	
See SDT response to your question in the SDT's FAC-011-4 Question 6 above	
Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	

Please see the response to NPCC RSC Group	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP does not object to R1 as proposed, we believe that Transmission Operators should be afforded opportunity to provide input into the process, even if not specifically designated within the standard.	
Likes 0	
Dislikes 0	
Response	
The proposed language is not specific on the method the RC uses to establish limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work. The requirement places the ultimate responsibility on the RC to establish limit, but by design does not specify how those limits are found or how the RC establishes them. The current language allows this without taking away flexibility and potential confusion on the responsibility.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the suggested approach. One point of clarification. Proposed requirement R4 states, "Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator	

Area in accordance with its SOL Methodology." Peak interprets this language to allow the RC the flexibility to either calculate this type of stability limit itself (i.e., the RC performs the calculation), or to utilize a TOP-calculated stability limit as the "established" stability limit, provided that the RC and the impacted TOPs accept its use. Please confirm that Peak's interpretation is accurate.	
Likes 0	
Dislikes 0	
Response	
The proposed language is not specific on the method the RC uses to establish limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work. The requirement places the ultimate responsibility on the RC to establish limit, but by design does not specify how those limits are found or how the RC establishes them. The SDT agrees the proposed language provides the RC the flexibility to either calculate this type of stability limit itself (i.e., the RC performs the calculation), or to utilize a TOP-calculated stability limit as the "established" stability limit	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

While Duke Energy agrees with the proposal of dividing the existing R1 into three requirements, we request the SDT to consider whether there is a reliability gap in allowing only the RC to establish IROLs. We recommend the drafting team consider the following:

R2. Each Transmission Operator shall establish SOLs (including the subset of SOLs that are IROLs) for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

Likes 0	
Dislikes 0	

Response

The SDT believes the ultimate responsibility to establish IROL belong to the RC. The SDT does not preclude RC involvement in helping establish SOLs especially where the RC's expertise may benefit the TOP.

The potential instability, uncontrolled separation, or Cascading outages could be found by the RC or could be a discussion initiated by a TOP. The proposed language is not specific on the method the RC uses to establish this limit, it could be via the RC's own study work, it could be the result of combined RC and TOP work, or it could be a verbatim adoption of the TOPs work.

The requirement places the ultimate responsibility on the RC to establish and declare the IROL. This is important because there are other IRO Reliability Standard requirements that need to be coordinated by the RC.

No modification was made to R2.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes

Document Name	
Comment	
Provided that the RC is limited in its ability to usurp the Transmission Owners rights in determining how Facility Ratings are determined, which are major components in SOL determination, than this proposal is acceptable. If the RC is not limited, then this is not acceptable as the RC should not be given the latitude to determine the amount of risk a Transmission Owner will accept through setting their methodology in determining an SOL, specifically a Facility Rating. The standard should only specify the end objective and not the process to achieve that objective.	
Likes 0	
Dislikes 0	
Response	
TheFAC-011-4 R2 to better reflect this concern.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

8. Existing FAC-014-2, Requirement R5, R5.2 requires the Transmission Operator (TOP) to provide its SOLs to its Reliability Coordinator (RC) and Transmission Service Providers (TSPs) that share its portion of the RC Area. The SDT is proposing in Requirement R3 of FAC-014-3 to exclude the TSPs from that communication chain. Other requirements in existing standards (MOD-028-2, Requirement R7, MOD-029-2a, Requirement R4, and MOD-030-3, Requirement R2.6) require the TOP to provide the Total Transfer Capabilities (TTCs), Total Flowgate Capabilities (TFCs), along with supporting information and assumptions to TSPs. Because the TTCs and TFCs already reflect the impact(s) of any SOLs, the SDT deemed retention of the existing language unnecessary. Do you agree with the proposed change? If not, please explain.

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response:	
Thank you for your vote, it is difficult to address your concerns without a comment.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with the exclusion of TSPs from Requirement R3 of FAC-014-3.	
Likes 0	
Dislikes 0	

Response:	
Thank you for your comment.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response:	
Please see NPCC Response.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with excluding the TSPs from the SOL communications path.	
Likes 0	
Dislikes 0	
Response:	
Thank you for your response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
NPPD agrees with removing TSPs from the notification requirements. The remainder of the requirement is also redundant with IRO-010-2 R1. As SOLs are a necessary input for OPA and RTA, the communication of them is required in the RC's data specification. As a result, including them here is redundant and unnecessary. Yes, the RC needs to know about changes to SOLs. The mechanism to notify them already exists in the data specification required by IRO-010-2 R1.	
Likes 0	
Dislikes 0	
Response:	
The team agrees that the information could be asked for by the RC under the IRO standards however we believe it is sufficiently important that it should be called out in its own requirement within the body of the SOL standards.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports NERC urging FERC to adopt Docket Number RM14-7-000, Comments of NERC in Response to NOPR MOD-001-2 (Available Transmission System Capability).	
Likes 0	
Dislikes 0	
Response:	
Thank you for your comment	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes the proposed changes would be beneficial and provide clarity.	
Likes 0	
Dislikes 0	
Response:	
Thank you for your comment	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response: Please see our response to the ISO/RTO Council Standards Review Committee.	

9. The SDT relocated the reliability objectives of existing Requirement R6 of FAC-014-2 into Requirement R6 of proposed Reliability Standard FAC-015-1 such that all Planning Coordinator and Transmission Planner responsibilities will be housed within one standard. Do you agree with the proposed change? If not, please explain.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA does not see the need for a new planning standard. The objective could be better accomplished by moving the requirement to existing planning standards. The annual system assessment is required to be provided to the RC per NERC standard IRO-017-1. The RC is in a better position to communicate with affected TOPs in the RC area if instability or uncontrolled islanding is identified in the system assessment.	
Likes 0	
Dislikes 0	
Response	
The drafting team believes that these requirements could be incorporated into a future revision of TPL 001 and FAC 013, however as a stop gap the team has proposed FAC 015 since that level of revision to the TPL 001 and FAC 013 would best be a separate SAR effort.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

Manitoba Hydro agrees that the Planning Coordinator responsibilities do not need to be in FAC-014-2. Manitoba Hydro would prefer if the responsibilities are related to FAC-013 or TPL-001 that the requirements be housed in one of those standards rather than create a new standard.	
Likes 0	
Dislikes 0	
Response	
The drafting team agrees that these requirements should be incorporated into a future revision of TPL 001 and FAC 013, however as a stop gap the team has proposed FAC 015 since that level of revision to the TPL 001 and FAC 013 would best be a separate SAR effort.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

ITC agrees with the retirement of FAC-010 and modifications to FAC-014-4 however does not believe that FAC-015 is necessary.	
Likes 0	
Dislikes 0	
Response	
The drafting team believes that these requirements could be incorporated into a future revision of TPL 001 and FAC 013, however as a stop gap the team has proposed FAC 015 since that level of revision to the TPL 001 and FAC 013 would best be a separate SAR effort.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that this requirement should be placed in TPL-001 since it is related to the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
The drafting team agrees that these requirements should be incorporated into a future revision of TPL 001 and FAC 013, however as a stop gap the team has proposed FAC 015 since that level of revision to the TPL 001 and FAC 013 would best be a separate SAR effort.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SCE finds the new SOL/IROL construct to be clearer and more useful. As the drafting team points out, Operations Time Horizon SOLs are not necessarily included in Planning Assessments required by TPL-001-4. SCE supports the reliability objectives established by FAC-015-1 and the relocation of these objectives from the in-effect FAC-014 to the proposed FAC-015.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports having the planners’ requirements contained in one standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	

Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

10. If you have any other comments that you haven't already provided in response to questions 7-9, please provide them here.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	
Document Name	
Comment	
ATC has the following additional comments on proposed FAC-014-3: R3: The SDT should strike requirement R3 since the content of this requirement is already covered by NERC standard IRO-010-2 R1 (i.e. this information or data is needed by the RC to perform its OPA and RTA as covered by R1.1). R4 and R5.2 through R5.4: The term "impacts" and "impacted" are used without definition. See ATC's comments to question #6 above about the need for a new sub-requirement under R4 of FAC-011-4 to ensure how impacted parties are identified is addressed in the RC's SOL methodology.	
Likes 0	
Dislikes 0	
Response	
The team believes there is some overlap with the TOP 003 and IRO 010 standards, but also believes the communications identified in FAC 14 are important enough to be called out explicitly rather than covered under the more general TOP/IRO requirements. Also TOP 003 does not currently require the RC to provide data to the TOP and only addresses TOP to TOP communication. The terms "impacts" and "impacted" are used in other standards. There is certainly room for an RC to further clarify how they determine if an entity is "impacted" however the team does not believe it's necessary to be more specific within the NERC standard.	
Michael Jones - National Grid USA - 1	
Answer	

Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Please see our Response to NPCC RSC Group comments.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	

We believe it will be more efficient for RCs to make their SOLs available to impacted entities through automated mechanisms, such as an on-line database portal, rather than providing the information as proposed. The proposed expectation would require direct communication between the RC and the impacted entities that would be documented through electronic communications or voice recordings. This would be a compliance burden on all entities involved. Moreover, this approach could introduce a natural latency when the RC provides the SOL information to external entities. This latency could impact a PC or TP who could have partially completed a Planning Assessment, only to find that the SOL data they used is outdated and that the assessment will need to be restarted. By pushing this information to an on-line portal, impacted entities can then pull the most current data set for monitoring and assessment purposes. We believe this change would convert the requirement to a more risk-based performance approach that shifts the focus of risk to the availability of the automated mechanisms.

We observe that part 5.4 is the only portion of this requirement that expects the RC to provide updated information to external entities. We ask the SDT to clarify this discrepancy in the other external entities identified in the requirement.

The proposed standard appears to miss the possible coordination between RC and an adjacent RC, particularly in the instance that an impacted TOP from an adjacent Reliability Coordinator Area would need information related to SOLs. There currently is no obligation listed under Requirement 5 that captures this instance.

We ask the SDT to move the IROL-related critical information to Requirement R1 where the RC is obligated to establish the IROL. The references listed under Requirement R5 are confusing, as they only pertain to the PC. For part 5.4, we believe the RC should provide the value of the stability limit or IROL, as identified in part 5.2.1, to an impacted TOP within its Reliability Coordinator Area. We believe Requirements R1 and R6 should be combined, as there is no expected timeframe identified when a RC is required to provide a list of generation or transmission Facilities that are critical to the derivation of the IROL. Transmission Owners ad Generation Owners could have compliance implications if the information is not provided in a timely fashion. The provision of this information should be done as soon as the IROL is established.	
Likes 0	
Dislikes 0	
Response	
o (Data Sharing) the team agrees and have modified the measure for R5 (and R6) of FAC 014 to better reflect that an online sharing of data would be acceptable. o (Part 5.4 updated information to other entities): Every part under R5 requires that information is provided on a schedule, and every time that information is provided it will have the current values. Part 5.2 requires that the PC receive the full list of information from the RC on an annual basis, receiving not only new values but also updated values and unchanged values. Part 5.4 specifies that the RC provides the data in 5.2.2-5.2.5 when it is first established, and thereafter provides only changes to the information on the agreed to time frame. So the PC and the TOP are both receiving the same information. The PC receives a full set of information each year. The TOP receives the full set of information once, and then only receives the changes to that data thereafter. Of course part 5.4 does not preclude the RC from sending the full set of information each transmittal, rather than just the changes. o *(RC to adjacent RC)* The drafting team believes that the specific case of SOL and IROL communication between RC's can occur under IRO-10-2 and does not need to be addressed in the FAC 014 standard. o *(IROL information to R1) The list of information under part 5.2 is for both Stability Limits and IROL. The list is referenced again in part 5.4 as needing to be sent to the TOP, and for brevity is not repeated under part 5.4. If the list were moved under R1 then it would apply to only IROL and not stability limits.*	

- (5.4 value of limit): Part 5.3 requires the sharing of the Stability and IROL limit values with the Transmission Operator and is a separate part from 5.4 to better accommodate different methods and time frames for providing the limits vs providing the additional information. This is based on the assumption that the limits may change more frequently than the underlying support information.
- (R1/R6 combine) The current requirement specifies that the Reliability Coordinator must communicate this information. This presumes that to show compliance the Reliability Coordinator will not only provide the information when first developed, but would also respond to any inquiries with either complete information or a confirmation on a lack of facilities. The drafting team did not believe it was necessary to establish a time frame for either new entries to be shared or for the reliability Coordinator to respond to a request. A transmission or generator owner who has not received information on a critical facility from their RC has no critical facilities until informed.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Comments: ERCOT provides the following additional feedback:

FAC-014:

ERCOT suggests the following clarification to R4 to simplify the language and to avoid the possible interpretation that the RC's authority (or duty) to establish stability limits that impact multiple TOPs would only be triggered in the event one or more TOPs has preliminarily established such a stability limit pursuant to its obligation under R2:

R4. Each Reliability Coordinator shall establish ***any*** stability limit to be used in operations ***in accordance with its SOL Methodology if that*** limit impacts more than one Transmission Operator ***in that*** Reliability Coordinator Area.

****Please refer to the attached comment form for redlined language.

Likes 0	

Dislikes 0	
Response	

The team reviewed the existing language and appreciates your feedback. The team believes the existing language is clear that the RC establishes the stability limit to be used in operations that impacts more than one Transmission Operator. The RC, the TOP or both may be the ones that actually do the calculation or identify that more than one Transmission Operator is impacted, but the RC would ultimately be responsible for establishing the limit based on their work or the work of others.

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	
Comment	

FAC-14-3 Requirement R5 no longer enforces that Reliability Coordinators *provide its SOLs and IROLs to those entities with a reliability need.* IRO-014-3 speaks to required information for Operating Plans, Procedures and Processes but does not address the need for critical details required for developing SOLs such as study reports and other related operating documentation. This information is necessary in order to satisfy requirements in FAC, TOP and IRO standards where there's potential impact to neighboring RC areas.

Furthermore, obtaining these critical details from other Reliability Coordinators and verifying their impact to SOLs through study can require a great deal of time and effort. It is recommended that more than 12 months be given in order to comply with this requirement. An appropriate time would be in the order of 24 – 36 months.

FAC-14-2 Requirement R6 had been the one requirement tying identification of multiple contingencies in the Planning Horizon to those that must be considered in Operations. This requirement had ensured that if instability as a result of a multiple contingency was identified in the Planning Assessment then that contingency should be deemed credible. It was the best vehicle to use to influence another RC/TOP area within the Interconnection to recognize a multiple contingency within its area if shown to impact other areas. In the interest of both assistance in respecting an IROL and operating a more reliable interconnected system some language to this effect should remain in FAC-14-3. The language should be expanded to reflect that multiples may be identified in the Operations Horizon as well through studies performed in deriving SOLs including those performed for OPA and RTA. Restricting the language to the planning horizon is insufficient as the planning horizon covers a more limited scope of system configurations realized in operations.

Likes 0	
Dislikes 0	
Response	

FAC-14-3 Requirement R5 requires that the RC provide its SOLS and IROLS to the TP, PC and TOP within its area. R5 does not extend to a neighboring RC because that RC can request the information as part of the IRO requirements.

The drafting team has modified the implementation plan out to 18 months, which the team believes is long enough to adapt to the changes within the standard.

The Drafting team agrees that FAC-14-2 Requirement R6 is important and it was moved to FAC 15 and expanded upon to include a wider range of events. FAC 11 R5.2 and 5.3 now address multiple contingency events within the operating horizon with R5 requiring that the RC consider any items found by the Planning Coordinator under FAC 15.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed

Answer	
Document Name	
Comment	
The use of the existing wording from FAC-014-2 “Facilities that are critical to the derivation of the IROL” causes a lot of confusion as to the mean of the word “critical”. The corresponding list of Facilities is referenced by other standards (e.g. CIP-002) with a major impact on compliance to those standards. With lack of clarity and guidelines on the intent regarding the “critical Facilities” that should be included per this requirement. The addition of “stability limits” causes even more confusion, as it is now understood that Facilities impacting SOLs stability limits not considered IROLs should be included on that list. The SDT should rework the purpose and rationale behind those requirements.	
Likes 0	
Dislikes 0	
Response	
This wording is consistent across multiple standards. The drafting team agrees that it may not be the ideal phrasing, but believes this change would best be handled by a team dedicated to changing this language across all effected standard simultaneously.	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Please see our responses to ISO/RTO Council Standards Review Committee	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
Requirement R5.5 is redundant with TOP-003-3 R1. This is input data necessary to perform OPA and RTA and so the communication of that data is already covered under this requirement. To include it in FAC-014-2 would be redundant and unnecessary.	
Likes 0	
Dislikes 0	
Response	
The team believes there is some overlap with the TOP 003 and IRO 010 standards, but also believes the communications identified in FAC 14 are important enough to be called out explicitly rather than covered under the more general TOP/IRO requirements. Also TOP 003 does not currently require the RC to provide data to the TOP and only addresses TOP to TOP communication.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	
Comment	
R4 - Developing stability limits should be the responsibility of the TOP, not the RC. TOPs should have greater familiarity with the studies and model details that are used to develop stability limits. The RC should only be involved where there is a discrepancy or question involving multiple TOPs having differing limits.	
Likes 0	
Dislikes 0	
Response	

The team has modified the wording in R4 and in the Rationale related to R4 to further clarify that the RC is responsible for setting the ultimate stability limit that impacts more than one TOP, however that does not mean the RC has to do the calculation. The RC may just be selecting one of the two TOP's calculations to use – if they aren't identical.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

Comment 1: The use of the term 'stability limit' in the proposed FAC-014-3 R4, R5.2 and R5.3 is ambiguous. In the definition of 'Reliable Operation' in the NERC glossary of terms, it lists:

"Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits… "

And from Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, page 8:

There are two types of stability limits: (1) Voltage stability limits… (2) Power (angle) stability limits…

Clearly there are multiple meanings of stability limits. CHPD requests the Standard Drafting Team to use additional language to clarify which 'stability limits' are meant here. The definition of Stability Limit, as a capitalized term in the NERC glossary of terms, unfortunately defines the Capitalized term 'Stability Limit' by the lowercase term 'stability limit', so of itself is not very useful as to identifying whether this is a thermal, voltage, or transient / dynamic type of phenomenon.

Comment 2: CHPD would recommend the following language to be used in the proposed FAC-014-3 R5.1. and 5.2 in place of, or in addition to the 'once every twelve calendar months' language. 'or within 30 calendar days (or a later date if specified by the requester)' to be consistent with the construct found in FAC-008-3 R8.2. Given the importance of SOLs (FAC-014-3 R5.1) and IROLs (FAC-014-3 R5.2), utilities may need ratings in a much more operationally appropriate timeframe than 12 calendar months.

Comment 3: In FAC-014-3 R5.5, the RC is required to provide SOLs for its RC area. However, the RC is not actually required to calculate SOLs (only IROLs). Therefore, any SOLs the RC has would be provided by the respective Transmission Operators in the RC area, as specified under

FAC-014-3 R3. The Standards Drafting Team may consider revising R5.5. to have Transmission Operators provide SOLs to other Transmission Operators, rather than the RC providing these SOLs. **Comment 4:** It would be useful to the PC for FAC-014-3 R5.2 to also include a sub-requirement for the RC to provide the PC with a description of the conditions where the IROL has been observed or was expected to be observed. For example, ‘in Winter with heavy south to north transfers’, etc. This way, the Planning Coordinator can better test its models to assess whether it can duplicate these conditions in the planning horizon. **Comment 5:** The language in FAC-014-3 R6 ‘Each Reliability Coordinator that is impacted by an IROL…” is unclear by the meaning of ‘that is impacted by an IROL’. It is thought that this probably could be removed from the requirement and the function of the requirement would be unaffected. **Comment 6:** The requirement for the Transmission Operator to provide SOLs in R3 is likely duplicative to requirements in IRO-010-2, R1. This requirement (IRO-010-2 R1) gives the Reliability Coordinator the authority to request this data. We are already providing these to the RC under IRO-010-2 R3, which requires us to provide this data in accordance with IRO-010-2 R1.	
Likes 0	
Dislikes 0	
Response	
(Stability Limit term usage) The Drafting team attempted within the standard and the associated rationales to provide guidance on what they meant by the term stability limit, please review those and let us know if that meets your need. In addition the MEITF will be further refining this concept within their work which may drive further changes to the standard in the future. (Annual not often enough) The Planning Coordinators activities are generally on an annual basis (TPL 001, FAC 013), and focused on distant years, therefore providing the SOL and IROL information on the minimum of annual basis supports that activity. The studies take substantial amounts of time to perform and because of that it is not uncommon for a small percentage of the information used in the study to have changed before the study is complete. Some information changes can be accommodated in the flow of the study, but others cannot and are captured on the next cycle of the study. Also nothing in the standard precludes the Planning Coordinator from requesting this information from the RC outside of the formal annual provision of the data, and thereby insure the Planning Coordinator is starting their study with the most recent set of information.	

(RC providing SOLs) The standard does not preclude a TOP from requesting SOL information from another TOP, and the TOP could arguably request that information from another TOP under TOP 003. From a FAC 14 perspective the team believed the RC was a reasonable clearing house for SOL data if a TOP wanted to formally request it under FAC 14. (Provide additional information with IROL or Stability Limit) The drafting team agrees and added a new requirement part to require the RC to provide this additional information system condition information with a stability limit or IROL> (Impacted RC) The situation where a Reliability Coordinator has established an IROL is clear, the Reliability Coordinator provides the related facilities. However a Transmission Owners Reliability Coordinator may not have an IROL that impacts the Transmission Owners facilities, but a neighboring Reliability Coordinator does. The Transmission Owners Reliability Coordinator is now an "impacted" Reliability Coordinator because while the IROL is not theirs, it does impact facilities within their area. The Transmission Owner's Reliability Coordinator is responsible for communication from between the Reliability Coordinators and between the Reliability Coordinator and its Transmission Owners. (Duplicative with IRO Standards) The team agrees that SOL information may arguably be requested under the IRO standards but felt that the communication of this information was sufficiently important to warrant its own requirement within the SOL standards.

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	
Document Name	
Comment	
OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments, taking these concerns into account the drafting team has withdrawn the proposed definition and incorporated language in to FAC 11 and FAC 14 to address what the expected system performance requirements are, and by extension what would constitute an SOL exceedance in real time monitoring, Real Time Assessments and Operational Planning Assessments.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Please see our responses to NPCC's comments.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections: Violation Severity Levels	

Requirement 3 VSL The VSL for Requirement R3 is in disconnect with the language in Requirement R3. The VSL for Requirement R3 references "the periodicity at which the RC needs such information" and Requirement R3 simply talks about "in accordance to the Reliability Coordinator's SOL Methodology." Requirement R7 in FAC-011-1 only notes, "The method shall address the periodicity of SOL communication." ReliabilityFirst recommends structuring the VSLs as follows (this is an example of the "lower VSL"): The Transmission Operator provided its SOLs to its Reliability Coordinator, but was late by less than or equal to 10 calendar days. Requirement R6 VSL The first part of the VSL for Requirement R6 ("The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL") does not match the language of Requirement R6. ReliabilityFirst recommends the beginning of the VSL state: Reliability Coordinator that is impacted by an IROL did not provide…	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the revised VSLs.	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	

OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, taking these concerns into account the drafting team has withdrawn the proposed definition and incorporated language in to FAC 11 and FAC 14 to address what the expected system performance requirements are, and by extension what would constitute an SOL exceedance in real time monitoring, Real Time Assessments and Operational Planning Assessments.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	
Document Name	
Comment	
The IROLs and SOLs calculated in FAC-014-3 are computed per the RC's SOL Methodology required per R1 in FAC-011-4. The longest time horizon for computing these is an Operational Planning Analysis, which addresses next-day operations. The SDT has not explained why RCs must provide SOLs and IROLs to PCs (R5.1) and other information (see R5.2) and least once every 12 months. Remember, the longest time frame for this information is next-day operations. However, requiring RCs to communicate their SOL Methodology to PCs and TPs per R8.2 in FAC-011-4 has some reliability benefit in that it communicates an operator's tools to planners.	
Likes 0	
Dislikes 0	
Response	

Under the proposed standard the RC develops SOL and IROL values. While the values are primarily used within the standards for the current and next day (OPA) analysis, that does not make them useless beyond the next day. Most of the SOL and IROL values can be relatively static. For example a line rating changes by expected ambient temperature but otherwise does not change day to day or year to year unless the line is modified. The same is true for a voltage limit and many stability limits. Those that aren't relatively static values can be translated by the Planning Coordinator into their time frame, if applicable. Communicating the values to the Planning Coordinator and Transmission Planner is necessary because FAC 015 requires them to use those limits (or more limiting criteria) in their Planning Assessments to insure that the system is planned the way it is operated.

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	
OGE agrees with the proposed changes in FAC-014-3. However, we disagree with the current proposed definition of SOL Exceedance. As indicated by multiple entities during the SOL/SOL Exceedance comment period, an exceedance can only occur if it happens in Real-time and therefore the SOL Exceedance definition should not incorporate the concept of predicted exceedances. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. OGE remains concerned with unintended impacts of separating the standard and the proposed SOL & SOL Exceedance definitions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, taking these concerns into account the drafting team has withdrawn the proposed definition and incorporated language in to FAC 11 and FAC 14 to address what the expected system performance requirements are, and by extension what would constitute an SOL exceedance in real time monitoring, Real Time Assessments and Operational Planning Assessments.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	

Comment	
In FAC-014-3, R4 as worded, entities that establish stability limits in advance of real-time (as allowed) may not have a mechanism to respond with mitigation plans or active 'tools' to respond when the RC communicates a newly emerged limit in near real-time. SRP recommends requiring the RC to guide mitigation when stability limits are changed in near real-time.	
Likes 0	
Dislikes 0	
Response	
Mitigation is within the TOP and IRO standard operating plans and not within the team scope. If a limit changes it is imperative that the TOP and RC work together to find a new operating plan to meet that revised limit, not introduce delays in instituting a limit.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
R 5.5 is redundant with TOP-003-3 R1. This is input data necessary to perform OPA and RTA and so the communication of that data is already covered under this requirement. To include it in FAC-014-2 would be redundant and unnecessary. As such, it is recommended that part 5.5 of R5 of FAC-014-2 be deleted.	
Likes 0	
Dislikes 0	
Response	
The team believes there is some overlap with the TOP 003 and IRO 010 standards, but also believes the communications identified in FAC 14 are important enough to be called out explicitly rather than covered under the more general TOP/IRO requirements. Also TOP 003 does not currently require the RC to provide data to the TOP and only addresses TOP to TOP communication.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	

Answer	
Document Name	
Comment	
While we agree with the changes to FAC-014, we will be voting “No” because of our problems with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see our responses under FAC 015 to your specific concerns.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
We suggest the intent of Proposed R6 be further clarified. In particular, the meaning of the word ‘derivation’ is ambiguous. We recommend changing ‘derivation’ to ‘determination’ of the limit.	
Likes 0	
Dislikes 0	
Response	
This wording is consistent across multiple standards. The drafting team agrees that it may not be the ideal phrasing, but believes this change would best be handled by a team dedicated to changing this language across all effected standard simultaneously.	
Wendy Center - U.S. Bureau of Reclamation - 5	

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
While we agree with the changes to FAC-014, we are voting “No” because of our Concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see our responses under FAC 015 to your specific concerns.	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	

Document Name	
Comment	
Recommend R5.5 be deleted. This is input data needed to perform OPA and RTA per the data specification developed in TOP-003-3 R1.	
Likes 0	
Dislikes 0	
Response	
The team believes there is some overlap with the TOP 003 and IRO 010 standards, but also believes the communications identified in FAC 14 are important enough to be called out explicitly rather than covered under the more general TOP/IRO requirements. Also TOP 003 does not currently require the RC to provide data to the TOP and only addresses TOP to TOP communication.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	

Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	
Response	
Thank you, please see our response to Southern California Edison.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
The existing SOL/IROL construct and specifically Planning Time Horizon SOLs create duplicative and unessential work. The proposed new construct is a major improvement and aligns the SOL/IROL reliability standards with best practices and the latest revision of TPL-001.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	
Document Name	
Comment	

As noted in our response to Question 7, the revised SOL definition is vital to ensure clear and accurate interpretation of FAC-011 and FAC-014 requirements. Therefore, we recommend that the revised SOL definition be included in the implementation plan for the revised FAC-011 and FAC-014 such that they all have the same effective date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the discussion of this topic under the SOL definition.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
The text “in accordance with” is subjective, and could be interpreted inconsistently across RE footprints as well as within RE footprints. For example, would the language from FAC-015-1 “equally limiting or more limiting than” be considered “in accordance with?”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In reviewing FAC 14 R1, R2 and R3, the drafting team considers “in accordance with” sufficiently clear that the TOP must follow with the Reliability Coordinators SOL Methodology. More clear than “consistent with” and more broad then equally limiting or more limiting.	

11. FAC-015-1 is predicated on the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative/restrictive/limiting than those found in (or established in accordance with) the RC's SOL Methodology, allowing for justified exceptions. Do you agree with this principle? If not, please explain.
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment
Assuming that the question should say "equal to or more conservative" rather than just "more conservative" than the Facility Ratings used by the RC/TOP, we agree with the principle, but find the language too confusing and disagree with the implementation. The phrase in R1 "If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology…" is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true). In addition, all of the requirements in FAC-015 are related to what limits should be used in planning assessments, therefore the requirements should be included in the TPL standard. Having a separate standard defining the limits that should be used in TPL studies adds unnecessary complication.

Likes 0	
Dislikes 0	

Response
You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting." Additionally, your statement regarding the use of emergency ratings correctly captures the SDT's intent. The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the

reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. The "established in accordance with" wording in the requirements is not intended to imply the RC usurps the owner-provided Facility Ratings. Rather, the intent was to reference the subset of owner-provided Facility Ratings the RC includes in its methodology. The SDT is considering alternate language to add clarity around this concept. FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
In general, the Facility Ratings established by the Transmission Owner, system steady-state voltage limits and stability criteria should be the same as the RC for facilities located within the Planning Coordinator area with some minor exceptions. The RC's SOL methodology may be less conservative in some cases, for example contingency selection. The RC will be mainly focusing on single contingencies while the PC will focus on single and multiple contingencies. However, the RC's methodology may be less conservative in terms of transmission service (i.e. considers non-firm use). In that case the RC may identify a stability limit whereas the PC did not.	
Likes 0	
Dislikes 0	
Response	
Requirements R1 – R3 of FAC-015-1 do not address contingencies. Their intent is to provide a mechanism for the coordination of Facility Ratings and System voltage/stability performance criteria between planning and operational studies.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No

Document Name	
Comment	
As stated in the current posted draft of FAC-015-1 R1, it (i.e., Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon) should be ***equal to*** or more conservative/restrictive/limiting.	
Likes 0	
Dislikes 0	
Response	
You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting."	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
Assuming that the question should say "equal to or more conservative" rather than just "more conservative" than the Facility Ratings used by the RC/TOP, we agree with the principle, but find the language too confusing and disagree with the implementation. The phrase in R1 "If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology…" is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true). In addition, all of the requirements in FAC-015 are related to what limits should be used in planning assessments, therefore the requirements should be included in the TPL standard. Having a separate standard defining the limits that should be used in TPL studies adds unnecessary complication.	
Likes 0	
Dislikes 0	

Response	
You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting." Additionally, your statement regarding the use of emergency ratings correctly captures the SDT's intent. The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. The "established in accordance with" wording in the requirements is not intended to imply the RC usurps the owner-provided Facility Ratings. Rather, the intent was to reference the subset of owner-provided Facility Ratings the RC includes in its methodology. The SDT is considering alternate language to add clarity around this concept. FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	
Refer to answer for #16.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No

Document Name	
Comment	
Proposed standard language not in alignment with Comment Form question. The language within Q11 would be correct (with a corresponding “YES” response) if it stated “should be equally or more”, which agrees with the actual language within the proposed language FAC-015-1 Requirements R1, R2 & R3. The language contained within this question goes beyond that principle, and would suggest that being equally conservative/restrictive/limiting might require a justified exception.	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
You are correct. The wording in the question should be “equally or more conservative/restrictive/limiting.”	
Bridget Silvia - Sempra - San Diego Gas and Electric – 3	
Answer	No
Document Name	
Comment	
Need consistency.	
Likes 0	
Dislikes 0	
Response	
Apologies but this comment is not clear and thus the SDT cannot address your potential concern.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	
Comment	
Duke Energy does not agree with the principle that Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be more conservative than those found in the RC's SOL Methodology. With this language, the drafting team is implying that it is not appropriate for Planners to plan and Operators to operate from the same or equal ratings without justification. We believe that it can be appropriate for Planning and Operations to use the same/equal ratings, and should not require justification to do so. We recommend the drafting team consider modifying the existing language to reflect that the use of the same/equal rating can be appropriate and not require justification.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with this sentiment. The actual wording in Requirements R1 – R3 of FAC-015-1 is consistent with what is expressed in this comment. The wording in the question should be "equally or more conservative/restrictive/limiting."	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York – 1	
Answer	No
Document Name	
Comment	
Day-to-day operations of the system may require a more conservative/restrictive/limiting Facility Ratings, System steady-state voltage limits, and stability criteria as the system can be operated beyond planning criteria (ex. beyond N-1/-1). Some operating margin is added into facility ratings, system steady state voltage limits, and stability criteria as System Operators are operating the system 24 hours for 365 days in a year which provides the Operators with unique operating challenges – various conditions (outages, generation commitment, contingencies that are beyond planning criteria) – that are beyond what's studied in TPL-001 Planning Assessment. System Operators may have, for example, pre-contingency low/high 'proxy' voltage limits for a particular substation as real time voltage collapse (knee of the curve) calculations are not performed for each operating state. System Operators also have at their disposal Dynamic Feeder Ratings which vary the capability of a feeder; which could be higher of lower than what's assumed in the TPL-001 Planning Assessment.	

The definition of System Operating Limit states: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria." FAC-015 would introduce operating criteria for multitude of operating system configurations into TPL-001 Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirements R1 – R3 and the associated rationale to add clarity regarding allowable exceptions. FAC-015-1 does not require additional simulations of System configurations beyond what is already required by TPL-001. It does require planners to use Facility Ratings and System voltage/stability performance criteria that are consistent with what is used in the operation of the applicable System or document any exceptions.	
Julie Hall - Entergy – 6	
Answer	No
Document Name	
Comment	
The question as worded states the limits should be more conservative, which Entergy does not agree with, the limit should be equally or more limiting. We believe this was just an oversight in the wording of the question since the proposed standard uses the word "equally".	
Likes 0	
Dislikes 0	
Response	
You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting."	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. – 1	
Answer	No
Document Name	
Comment	

Please refer to the comments submitted by the SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Answer provided to SPP Standards Review Group comments	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

Comment 1: Facility Ratings should be provided by the Transmission Owner and Generation Owner to both the Planning Coordinator and Reliability Coordinator. Facility Ratings are what they are – from our experience, the trouble comes in with assumptions about ambient conditions.

In CHPD's experience, the greatest challenge between planning and operations is that we utilize dynamic ambient-temperature based ratings. In real-time, there is a very wide band of potential transmission line ratings based on the ambient temperature, just as there are a wide range of ambient temperature conditions throughout the day. Therefore, in real-time operations we use many ratings throughout the day.

In long term system planning and operations planning, it is clearly inappropriate to run all the studies through all ratings sets. Our practice is to use what we as a utility have felt is appropriate for the expected ambient conditions, in coordination with our neighbors.

Similarly, while it is recognized that there are differences between the planning and operational voltage criteria, CHPD has not experienced great difficulty in operating its system, even with the different planning and operational criteria.

CHPD feels that there isn't a need to create prescriptive requirements in order to accomplish this reliability objective. It is the Planning Coordinator's responsibility to adequately plan the system for growth, capacity, and integration of service in the Planning Horizon; it is the Reliability Coordinator's responsibility to plan and operate the system in the Operations Horizon. Given these different responsibilities, we feel it is not appropriate for one entity to determine another entity's criteria since each performs a different system function in a different system timeframe.

Comment 2: The term 'System Operating Limit (SOL)' from FAC-014-2 has now been replaced with 'Facility Ratings' in FAC-015-1. While System Operating Limits (SOLs) are the result of *studies* assessing the performance of Facility ratings and performance criteria against

expected system conditions and events, Facility Ratings are ***not*** the result of studies and assessments – they 'are what they are'. Furthermore, under FAC-008, the Transmission Owner and Generator Owner is already required (under FAC-008 R6-R8) to make its Facility Ratings available to the Reliability Coordinator and Planning Coordinator. Under FAC-015-1 R4, the Planning Coordinator is now being required to provide Facility Ratings. While this was in the spirit of what was previously in FAC-014-2 with 'SOL' replaced with 'Facility Ratings', this change is now requiring the Planning Coordinator to provide something that is the responsibility of the Transmission Owner under FAC-008 to provide. CHPD recommends removal of this requirement because its objective is carried in FAC-008.	
Likes 0	
Dislikes 0	
Response	
Comment 1 The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. The point on ambient assumptions with regards to Facility Ratings is well taken. The SDT is modifying Requirement R1 and the associated rationale to clarify the allowable exceptions. The primary intent of Requirement R1 is to address the potential scenario of planning entities using less limiting Emergency Ratings (time-dependent) than those used in the operation of the System. The point on voltage criteria is well taken as well. In the operational and real-time horizons, operators will typically maintain voltage as close to nominal/desired levels as possible and will likely have guidelines stating as much. The System Voltage Limit, however, is the absolute highest/lowest level the operator can stand without taking pre-contingency action such as load shed. If the applicable planning entities still maintain an acceptable voltage range outside of these System Voltage Limits, a technical rationale will need to be documented and communicated consistent with the requirement. FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the proposed FAC-015 or a modification to existing standards. Comment 2 The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the	

reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings.
The SDT is proposing a new construct as described in its whitepaper, Rationales for FAC-010-3 (Retirement) and FAC-015-1, which is included as supporting documentation in the NERC ballot. This construct, along with the SDT's draft SOL definition revision, make use of the concept that SOLs are Facility Ratings, System Voltage Limits, and stability performance criteria used in operations. This is to remove ambiguity with the concept of SOLs that has led to a lack of consistency and confusion in the term's application across industry and to eliminate the notion that operating limits exist in long-term planning. The SDT, therefore, did not replace SOL with Facility Rating as you stated in the above comment, but it removed the notion of SOLs in the planning horizon.

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	No
Document Name	

Comment

As stated in proposed Reliability Standard FAC-015-1 R1, Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments for the Near-Term Transmission Planning Horizon should be **equal to or more conservative/restrictive/limiting**…

Likes 0	
Dislikes 0	

Response

You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting."

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment	
FMPA agrees in principle, but as mentioned above, there should be a feedback loop. More information about how to coordinate the planning horizon events with the operations horizon events would be useful, and a table describing the various time horizons, contingencies, and allowable actions, such as Table 1 of TPL-001-4, may help add clarity.	
Likes 0	
Dislikes 0	
Response	
The stated purpose of FAC-015-1 is "To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology." The requirements in this standard are not intended to address contingencies or allowable actions as this is governed by TPL-001.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC agrees with the general concept that more or at least as conservative SOL's should be utilized in the Planning Assessments as those considered in real time operations. The SDT should clarify how exceptions would be justified and who would have the authority to justify them. There will be instances where lower Facility Ratings will be identified in real time as Facility Ratings are continually reviewed by TO's. This will create situations when more limiting SOL's may be used in real time operations that those that were used in the latest or even current Planning Assessments. There will also be projects considered in future Planning models that may increase Facility Ratings or other SOL's. It should be made clear that this would be acceptable. The standard should only specify the end objective and not the process to achieve that objective. Each system has a defined Planning Criteria that is published and readily available to the RC. This Criteria has defined voltage limits and stability criteria that have been identified that work with the Facility Ratings for that system. By utilizing an RC based methodology, you will be forced to go to either a least common denominator criteria or not be able to take in to account specific issues inherent in a system. Having to justify each exception for every rating change due to a project, rating correction, use of seasonal ratings in operations is not prudent for either the PC or the TP.	

ITC does not believe FAC-015-1 is necessary to achieve the required outcome. Simple modifications to TPL-001-4 may allow for the same desired outcome.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions. FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the proposed FAC-015 or a modification to existing standards. Currently, the SAR for this project does not allow the modification of other standards such as TPL-001.	
David Jendras - Ameren - Ameren Services – 3	
Answer	No
Document Name	
Comment	
We agree with the concept that system performance criteria used in the Planning Assessments should be more restrictive or at least line up with system performance criteria used in the Operating Horizon. But, system performance criteria used in the Operating Horizon cannot be more restrictive than those used in the Planning Horizon. The proposed standard, as written, allows the RC to establish criteria without consultation with the TP and the PC. In our opinion, this is a recipe for failure. Furthermore, we see nothing in the NERC Functional Model that would allow the PC and RC to develop or establish system performance criteria as part of their defined roles, or to establish performance criteria that could be more restrictive than the criteria provided by the Transmission Owners and Transmission Planners. Standard TPL-001-4 dictates system performance requirements. PC and RC cannot arbitrarily decide to come up with new, more restrictive system performance criteria. We are also concerned that requirements R1 through R3 allow for no input from the Transmission Planners regarding the development of any performance criteria established by the Planning Coordinator. Requirement R4 then requires the PC to simply hand-down its criteria to the Transmission Planner without any input as to whether the criteria are reasonable or whether meeting the criteria is feasible. At a minimum,	

requirements R1 through R3 need to recognize that the development of any PC based system performance criteria has to be a collaborative effort between the PC and the TPs and the Transmission Owners. Any tightening of performance criteria will likely require capital investment and we need to hear from the Planning Coordinators as to why the planned system needs to meet the new, more stringent reliability requirements. Requirements R1 through R3 require the Planning Coordinator to provide a technical justification to the Reliability Coordinator for using less limiting ratings, voltage limits, or performance criteria. We can see that some equipment ratings can change from year to year, and perhaps the corrective action plans should also be provided for those parts of the system that have been or are planned to be upgraded. However, we disagree with the approach proposed by the SDT for the voltage limits and stability criteria, and instead believe that the drafting team needs to have the Reliability Coordinator provide a technical basis to the Planning Coordinator and the Transmission Planners regarding why more limiting ratings and performance criteria should be required in planning assessments. As any tightening of ratings and performance criteria will likely require capital investments, we need to hear from the Reliability Coordinators as to why the system as provided/planned needs to meet the new, more stringent reliability requirements.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 is not intended to allow the RC to dictate criteria on planning entities who are not under the authority of the RC. The intent is to ensure the system is planned in a manner that is conducive to the reliable operation of that system. If planning entities use less limiting criteria, the standard does require documentation as to why less limiting criteria were used but does not give the RC authority to accept or reject that documentation. The PC to TP communication does not imply the process of determining performance criteria or modeling assumptions is not a joint effort by the PC and the TP. The rationale for R1 even speaks to the joint effort required by MOD-032-1 as being the appropriate mechanism for the coordination of Facility Ratings in planning models. The SDT is revising the language in the requirements to add clarity regarding exceptions to R1 – R3 and to simplify the language around the PC/TP communication path.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
The SPP Standards Review Group would like the drafting team to provide some clarity on the short term der-ates pertaining to the Planning Horizon. Also, we would ask the drafting team to provide clarity on what are justified exceptions or how the term is defined.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions.	
James Grimshaw - CPS Energy – 3	
Answer	No
Document Name	
Comment	
Planning Assessments for the Near-Term Transmission Planning Horizon utilize base case models built meeting requirements in MOD-032. These base case models incorporate future additions and upgrade projects that may be put in place to resolve existing SOLs. Assessing the continuing need for Corrective Action Plans, as required by TPL-001, would address the need to study the existing SOLs, however, to properly evaluate other future projects, assumptions must be made that existing Corrective Action Plans will be implemented. This means, for example, that studies performed for year 5 should assume that Corrective Action Plans identified for Year 2 have already been implemented, which means an existing SOL may have already been upgraded when studying Year 5.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions including rating changes that are the result of a CAP.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico – 1	

Answer	No
Document Name	
Comment	
PNMR believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA. Instead of allowing for exceptions, PNMR suggests that the RC, TOP, and PA should jointly develop system performance criteria. PNMR suggests that R1 be revised to provide clarity on what is less conservative/restrictive/limiting. Is it the intention of the SDT that the Planning Coordinator would have to provide a technical justification to the RC for using less limiting Facility ratings based on a Corrective Action Plan? For example, Facility A has a rating of 100 MVA. A previous Planning Assessment identified an overload of Facility A. To mitigate the overload the Corrective Action Plan is to increase the rating of Facility A to 200 MVA. TPL-001-4 R1.1.3 requires the Planning Coordinator to include this planned change to the existing Facility in the System model used for the Planning Assessment. Does this situation result in the Planning Coordinator using a less limiting Facility Rating than established in accordance with the RC's SOL Methodology? PNMR strongly believes that the Planning Coordinators should not have to provide technical justification to their RC for simply following the TPL-001 standard.	
Likes 0	
Dislikes 0	
Response	
The potential for "gaps" between planning and operations exist today. The addition of FAC-015 will, at a minimum, facilitate recognition of these "gaps" where they exist. The SDT did not take the route of requiring the PC to jointly develop criteria with TOPs and RCs due to the fact that the PC is not under the jurisdiction of the RC and the RC is not under the jurisdiction of the PC. Therefore, there would be no entity that had the authority to effectively force a set a common criteria on the other should joint efforts fail. The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions including rating changes that are the result of a CAP.	
Gladys DeLaO - CPS Energy – 1	
Answer	No
Document Name	

Comment	
Planning Assessments for the Near-Term Transmission Planning Horizon utilize base case models built meeting requirements in MOD-032. These base case models incorporate future additions and upgrade projects that may be put in place to resolve existing SOLs. Assessing the continuing need for Corrective Action Plans, as required by TPL-001, would address the need to study the existing SOLs, however, to properly evaluate other future projects, assumptions must be made that existing Corrective Action Plans will be implemented. This means, for example, that studies performed for year 5 should assume that Corrective Action Plans identified for Year 2 have already been implemented, which means an existing SOL may have already been upgraded when studying Year 5.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions including rating changes that are the result of a CAP.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
The proposed Standard places the onus on the PC to provide the criteria to be used by the Transmission Planner in completing Planning Assessments. In SPP, the SOLs have historically been defined as permanent and temporary flowgate ratings and operating guides. Based on that methodology, it is difficult, if not possible, for planners to identify all situations that potentially may cause an operating guide that would lower a rating; and, as such, the planner may not study each SOL in their Planning Assessment.	
Likes 0	
Dislikes 0	
Response	

The SDT is proposing a new construct as described in its whitepaper, Rationales for FAC-010-3 (Retirement) and FAC-015-1, which is included as supporting documentation in the NERC ballot. This construct, along with the SDT's draft SOL definition revision, make use of the concept that SOLs are Facility Ratings, System Voltage Limits, and stability performance criteria used in operations. This is to remove ambiguity with the concept of SOLs that has led to a lack of consistency and confusion in the term's application across industry and to eliminate the notion that operating limits exist in long-term planning. However, the primary elements of SOLs (Facility Ratings, voltage/stability limits) should be coordinated in planning models/studies such that they support how that system is actually operated.

Thomas Foltz - AEP – 5	
Answer	Yes
Document Name	
Comment	
As previously posed in our response to Question 10, would the language from FAC-015-1 "equally limiting or more limiting than" be considered "in accordance with" as provided in FAC-014-3?	
Likes 0	
Dislikes 0	
Response	
The "in accordance with" language was not used in FAC-015 because the RC does not have the authority to dictate to planning entities. The "equally limiting or more limiting than" language was used as a more descriptive phrase than other terms such as "coordinate."	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
While we agree with the principle, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements to existing standards or modifying existing standards.	

Planning assessments modeling data including facility ratings are based on MOD-032-1 data requirement. If it is desired to coordinate modeling data with RC SOL methodology, RC SOL methodology should align with the MOD-032-1 requirement instead of drafting a new requirement.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the proposed FAC-015 or a modification to existing standards. Currently, the SAR for this project does not allow for the modification of other standards such as MOD-032. The rationale for R1 speaks to the modeling requirements of MOD-032-1 as being the appropriate mechanism for the coordination of Facility Ratings in planning models. The requirements of FAC-015 do not usurp this, however their intent is to add bounds to the Facility Ratings such that they align with how the system is actually operated. Exceptions should be documented appropriately but the RC cannot dictate modeling data to planning entities based on the NERC Functional Model.	
Michelle Amarantos - APS - Arizona Public Service Co. – 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the principal but does not agree that there is a need for R1, R2 and R3 as they provide minimal additional reliability benefits and create an unnecessary additional burden for the Planning Coordinator.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the	

proposed FAC-015 or a modification to existing standards. The SDT is revising the wording in the standard to clarify allowable exceptions (R1 – R3) with the intent to minimize unnecessary documentation requirements regarding potential exceptions being used.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
SCE supports this principle and believes that best planning practices include more restrictive or equal limits compared to operational limits to provide our transmission operators with the necessary grid assets or advanced knowledge of system limitations to reliably operate the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the principle, but has a concern with the wording of R1. -R1 refers to Facility Ratings as being established in accordance with the Reliability Coordinator’s SOL Methodology, though Facility Ratings are established by a TO or GO in accordance with their FAC-008-3 Facility Ratings methodology. Perhaps the requirement should read “…the Facility Ratings used to establish SOLs in accordance with the RC’s SOL Methodology...”	
Likes 0	
Dislikes 0	

Response	
The rationale for Requirement R1 states, “The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System.” In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor “owner-provided” to the reference for Facility Ratings.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The SDT is definitely on target with its assessment that the system must be planned to at least as conservative limits as are used in the operation of the system in real-time. Because planning analyses cannot cover all operating conditions to do any different would be to plan a system that could not be operated within acceptable limits.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Downey - Peak Reliability – 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with this principle.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response.	
See response to NPCC comments	
Richard Vine - California ISO – 2	
Answer	Yes
Document Name	
Comment	
We agree with the principle, but we disagree with the implementation. We agree with the following comment from Seattle City Light: *The phrase in R1 "If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology…" is confusing since Facility Ratings are established by the TO in accordance with FAC-008, not by the RC or TOP in accordance with the SOL Methodology. If the intent is to ensure that, for example, the PC/TP does not plan to 15-minute emergency ratings if the TOP uses only 30-minute emergency ratings in operations, then it should make that more explicit. The requirements seem to imply that there could be more than one set of Facility Ratings for a given Facility (not true) and that Facility Ratings are established in accordance with the RC SOL Methodology (also not true).*	

Proposed alternative language for R1: In planning assessments and operations, facility continuous ratings shall be used for the pre-contingency state and facility ____ hour/minute ratings shall be used for the post-contingency state. As stated in the purpose section of FAC 008 a Facility Rating is essential for the determination of System Operating Limits. We disagree with the notion that Facility Ratings are SOLs. While Facility ratings are based on characteristics of the Facility in accordance with FAC 008, SOLs are system limits developed using steady state and stability simulations based on a defined set of performance criteria such as those defined in the currently effective FAC-010 and FAC-011 standards. The required coordination between planning and operations can better be addressed by the regional reliability organization like WECC which has an open and established process for developing regional criteria. Reliability coordinators' SOL methodologies are developed without input from planning coordinators. Given the objective is to ensure coordination between planning and operations, the RC must be assigned a responsibility in the standard. For example, if the standard entails comparing planning models with operations models, then the RC must have the responsibility to provide the operations models and the obligation to timely respond to questions the PC may have in the course of the comparison in order to resolve any discrepancy in facility ratings, etc. Requirement R1 of TPL 001-4 requires the planning coordinator to use modelling data provided in accordance with MOD 10 and MOD 12 (which are now replaced with MOD 32). As such using modelling information such as facility ratings obtained from the reliability coordinator's SOL methodology can be inconsistent with TPL 001-4. The ratings and limits used in planning do not have to be more conservative than those used in operations. Equally conservative ratings and limits can be sufficient. For example, a 0.9 p.u. low voltage limit can applicable in both planning and operations. CAISO PC proposes Requirements R1 to R5 be replaced with something like: Planning Coordinators (PCs), Transmission Planners (TPs), Reliability Coordinators (RCs) and Transmission Operators (TOPs) within a Regional Reliability Organization (RRO) area shall collaborate in developing and implementing consistent applicable Facility Ratings duration criteria, System steady-state voltage limits, and stability criteria for use in planning assessments and operations.	
Likes 0	
Dislikes 0	
Response	
The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings.	

It is the opinion of the SDT that the notion that SOLs are based on a set of criteria is problematic and is one of the sources of confusion regarding the use of this term throughout the industry. Clarifying that SOLs are Facility Ratings and voltage/stability limits/criteria used in operations is a fundamental concept that is necessary to remove this ambiguity. The rationale for R1 speaks to the modeling requirements of MOD-032-1 as being the appropriate mechanism for the coordination of Facility Ratings in planning models. The requirements of FAC-015 do not usurp this, however their intent is to add bounds to the Facility Ratings such that they align with how the system is actually operated. Exceptions should be documented appropriately but the RC cannot dictate modeling data to planning entities based on the NERC Functional Model. The actual wording in Requirements R1 – R3 of FAC-015-1 is consistent with what is expressed in this comment. The wording in the question should be “equally or more conservative/restrictive/limiting.” The SDT did not take the route of requiring the planning entities to jointly develop criteria with operating entities due to the fact that planning entities are not under the jurisdiction of the operating entities and operating entities are not under the jurisdiction of planning entities. Therefore, there would be no entity that had the authority to effectively force a set a common criteria on the other should joint efforts fail.	
Gregory Campoli - New York Independent System Operator – 2	
Answer	Yes
Document Name	
Comment	
However it is not clear on how to handle situations when the planning assessment was performed with the equal or more conservative limit and actual conditions change resulting in more restrictive limits in the Operating Horizon. Note: ERCOT does not support this response	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in the standard and the associated rationale to add clarity regarding allowable exceptions.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	

Answer	Yes
Document Name	
Comment	
ERCOT reads the standard to say that the values used in Planning Assessments could be *equal or* more limiting than those used in the RC's SOL Methodology, and not that they must be more limiting, as suggested by the question.	
Likes 0	
Dislikes 0	
Response	
You are correct. The wording in the question should be "equally or more conservative/restrictive/limiting."	
John Merrell - Tacoma Public Utilities (Tacoma, WA) – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable – WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. – 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA – 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

12. Do you agree that coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria as required in Requirements R1-R3 should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Based upon NPCC's comment, this is the SDT's response: The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. Nothing in the SDT's choice precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons.	
Gladys DeLaO - CPS Energy - 1	
Answer	No

Document Name	
Comment	
Coordination for SOLs should be incorporated into base planning models required by MOD-032, the same as Facility Ratings are incorporated into these base models (as required by MOD-032). TPL-001 requirements would then stay the same, as these studies should be based upon models built as required by MOD-032. FAC-015 Requirement R1 may be more appropriately incorporated into the FAC-008 facility rating as part of the MLSE calculation for individual facilities. For groups of facilities, identification of a limiting flow-gate may be more appropriate. If this is not feasible, then the requirement should be incorporated into the modeling requirements of MOD-032.	
Likes 0	
Dislikes 0	
Response	
The proposed FAC-015-1 standard, with requirements R1 through R3, would require coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria by the Planning Coordinators and Transmission Planners with the Reliability Coordinators. This activity is not creation of data for a basecase, exclusively, so the SDT does not feel it appropriate for inclusion with the MOD-032-1 standard. In addition, since this is a coordination action, and not a rating creation activity, the SDT does not believe it appropriate for inclusion within FAC-008-3.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that this language continues to create a gap between planning and operations. PNMR proposes the removal of the phrase “of the Near-Term Transmission Planning Horizon”. Long-Term planning should be performed to the same or more stringent Facility Ratings, System steady state voltage limits, and stability performance criteria.	
Likes 0	

Dislikes 0	
Response	

The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. Nothing in the SDT’s choice precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons.

James Grimshaw - CPS Energy - 3

Answer	No
Document Name	
Comment	

Coordination for SOLs should be incorporated into base planning models required by MOD-032, the same as Facility Ratings are incorporated into these base models (as required by MOD-032). TPL-001 requirements would then stay the same, as these studies should be based upon models built as required by MOD-032. FAC-015 Requirement R1 may be more appropriately incorporated into the FAC-008 facility rating as part of the MLSE calculation for individual facilities. For groups of facilities, identification of a limiting flow-gate may be more appropriate. If this is not feasible, then the requirement should be incorporated into the modeling requirements of MOD-032.

Likes 0	
Dislikes 0	
Response	

The proposed FAC-015-1 standard, with requirements R1 through R3, would require coordination of Facility Ratings, System steady state voltage limits, and stability performance criteria by the Planning Coordinators and Transmission Planners with the Reliability Coordinators. This activity is not creation of data for a basecase, exclusively, so the SDT does not feel it appropriate for inclusion with the MOD-032-1

standard. In addition, since this is a coordination action, and not a rating creation activity, the SDT does not believe it appropriate for inclusion within FAC-008-3.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
If premise is to ensure consistency with TPL-001-4, then language within Standard should reference, "...annual Planning Assessment.." versus just the near-term horizon	
Likes 0	
Dislikes 0	
Response	
The annual Planning Assessment includes both a Near-Term and Long-Term Planning Horizon portion. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. Nothing in the SDT's choice precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	No
Document Name	
Comment	

We expect the FR and limits used in the TPL assessments to be very similar if not identical in most cases between the near-term and long-term horizons. Since most major transmission projects are identified in the long-term horizon and take several years to be completed, it would make no sense for the PC/TP to use less limiting criteria for the long-term horizon than the near-term horizon or the RC's SOL Methodology. We suggest removing the reference to Near-term horizon and simply referring to the Planning Assessment as in R4.	
Likes 0	
Dislikes 0	
Response	
The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. Nothing in the SDT's choice precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group has a concern pertaining to the performance of meeting Requirements R1 and R2. They should be limited to the near term BES representation of year one and two in the near term planning horizon power flow cases set. The BES representations will differ between the Operations and Planning power flow cases due to the proposed project to meet Planning Assessment needs for the year 5 through 10 models.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates the comment from the SPP Standards Review Group. The SDT had to choose a set of Planning Assessments for comparison and, for simplicity's sake, chose the Near-Term Planning Horizon. The SDT recognizes that, with regard to proposed Requirement R1, there is likely to be differences to be documented between Planning and Operations with regard to Facility Ratings. Those differences will have to be communicated to the Reliability Coordinator at some point, so the SDT views the choice of providing that information from the 5 year model versus 2 year model as not significant. The SDT, while allowing for System steady-state voltage limits differences in Requirement R2, did not expect many to exist among cases examined in the Near and Long Term Planning Horizons. If such differences exist, then there should be a technical reason for the difference so that understanding, at a minimum, would occur and potentially resolution, if appropriate. The Planning Coordinator or Transmission Planner would provide the technical rationale; at most the Reliability Coordinator reviews the rationale but does not approve or reject it.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The same concepts that apply to the Near-Term Transmission Planning Horizon should apply to the Long-Term Planning Horizon. ITC agrees with the general concept that more or at least as conservative SOL's should be utilized in the Planning Assessments as those considered in real time operations. The SDT should clarify how exceptions would be justified and who would have the authority to justify them. There will be instances where lower Facility Ratings will be identified in real time as Facility Ratings are continually reviewed by TO's. This will create situations when more limiting SOL's may be used in real time operations that those that were used in the latest or even current Planning Assessments. There will also be projects considered in future Planning models that may increase Facility Ratings or other SOL's. It should be made clear that this would be acceptable. Per FAC-008-3, Facility Ratings are calculated by the TO and communicated to the TP and TOP (typically all within the same organization) and to the PC and RC. These ratings are used throughout both the Near-Term and Long-Term Planning Assessments unless a planned project causes them to change or a project that is under construction goes in service. Coordination occurs today and should be allowed to continue without strict dictates on exactly how each organization will perform their work. The standard should only specify the end objective and not the process to achieve that objective.	

Likes 0	
Dislikes 0	

Response

The proposed FAC-015-1 does not specify the process by which these activities are accomplished. The proposed standard merely requires that a process exists and some minimal information be provided as part of the effort. If an entity already has a process to accomplish the described effort, then meeting the proposed standard should pose little to no concern. The standard has been proposed, in part, for those entities that have no existing process, and with the retirement of FAC-010-3. The SDT expects most differences to simply be differences in Facility Ratings due to Planning Coordinators or Transmission Planners having identified the need to upgrade a Facility to resolve an issue found in past Planning Assessments. Nothing in the SDT's choice precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

We question what the value of R1-R3 is and if the requirements are even needed. R1-R3 are really dealing with TPL-001-4 and there shouldn't be three additional requirements in FAC-015-1 to deal with the uncommon occurrence of a PC using less limiting Facility Ratings, System steady-state voltage limits, or stability performance criteria. It certainly shouldn't require a technical justification, it should only require coordination

Likes 0	
Dislikes 0	

Response

The SDT understands your perspective with regard to the proposed standard. During our discourse over it, the very point you note was discussed. What our collective dialogue uncovered was the fact that no standard requires this data, used in both Operations and Planning, to be coordinated. In addition, our discussions uncovered current examples where the coordination does not occur as well as it might otherwise. Finally, with the retirement of FAC-010-3, the opportunity to compare, explicitly, SOLs in the Planning Horizon and Operations Horizon is removed. For these reasons, and the need to have coordination between the Reliability Coordinator and the Planning Coordinator and Transmission Planners, the SDT determined there was a need for the proposed standard FAC-015-1.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
The TPL-001-4 study requires MOD data to be used in TPL-001-4 R1. This includes the rating of transformers and transmission lines. Voltage limits (including the stability performance of the voltage) is addressed in TPL-001-4 R6 and are the required criteria for the Planning Assessment. These requirements are applicable to both the Near-Term Transmission Planning Horizon and the Long-Term Planning Horizon. Specifying the time horizon in FAC-015-1 should not be done because it does not modify the time frame requirement found in TPL-001-4 for when these thermal and voltage limits should be used. CHPD feels this language should be removed from FAC-015-1 R1-R3.	
Likes 0	
Dislikes 0	
Response	
Nothing in the SDT's choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only.	

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Please refer to the comments submitted by the SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Response given to the comment of the SPP Standards Review Group: The SDT appreciates the comment from the SPP Standards Review Group. The SDT had to choose a set of Planning Assessments for comparison and, for simplicity's sake, chose the Near-Term Planning Horizon. The SDT recognizes that, with regard to proposed Requirement R1, there is likely to be differences to be documented between Planning and Operations with regard to Facility Ratings. Those differences will have to be communicated to the Reliability Coordinator at some point, so the SDT views the choice of providing that information from the 5 year model versus 2 year model as not significant. The SDT, while allowing for System steady-state voltage limits differences in Requirement R2, did not expect many to exist among cases examined in the Near and Long Term Planning Horizons. If such differences exist, then there should be a technical reason for the difference so that understanding, at a minimum, would occur and potentially resolution, if appropriate. The Planning Coordinator or Transmission Planner would provide the technical rationale; at most the Reliability Coordinator reviews the rationale but does not approve or reject it.	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

NERC TPL-001 Planning Assessment should have Facility Ratings, System steady state voltage limits, and stability performance criteria established for both Near-Term and Long-Term Transmission Planning Horizon, however these should be defined separately from RC's SOL Methodology.	
Likes 0	
Dislikes 0	
Response	
The proposed FAC-015-1 standard continues to allow the Facility Ratings, System steady state voltage limits, and stability performance criteria established for the NERC TPL-001-4 Planning Assessments to be established independently from those used by the RC using its SOL methodology. What the proposed standard does do, however, is require the implementation of a process to result in Facility Ratings, System steady state voltage limits, and stability performance criteria that are equal or more limiting to those used in Operations, or the difference is explained. The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Desire consistency.	
Likes 0	
Dislikes 0	
Response	

The SDT requests more detail in the comment in order to provide a proper response.	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Peak believes that requirements R1 through R3 should also apply to other NERC required assessments such as the Transfer Capability assessments required by FAC-013-2. It is important for reliability that these Transfer Capability assessments abide by the same principles as the Planning Assessments for the Near-Term Transmission Planning Horizon. Otherwise the Transfer Capability assessments could use a different set of Facility Ratings, System Voltage Limits, and stability criteria than those established in accordance with the RC's SOL Methodology, which propagates the problems that are being addressed by FAC-015-1 Requirements R1 through R3.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment. The SDT believes that the Facility Ratings, System steady state voltage limits, and stability performance criteria developed for Planning Assessments for NERC standard TPL-001-4 should be identical to those used for other Planning Assessments, including those required by FAC-013-2. The SDT wants to keep the proposed standard as simple as possible, and chose not to include other sets of Facility Ratings, System steady state voltage limits, and stability performance criteria due to our belief that one set should be common among all planning analyses.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	

Likes 0	
Dislikes 0	
Response	
See response to Q16.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF believes there is insufficient technical reason to exclude the Long-Term Transmission Planning Horizon from Requirements R1-R3. The use of different Facility Ratings, System steady state voltage limits, and stability performance criteria between the Near-Term and Long-Term Transmission Planning Horizons has the potential to be problematic. To ensure consistency with Reliability Standard TPL-001-4, which includes both the Near-Term and Long-Term Planning Horizons in the Planning Assessment, recommend the following change to R1-R3: Each Planning Coordinator… used in its annual Planning Assessment are equally limiting…	
Likes 0	
Dislikes 0	
Response	
Nothing in the SDT's choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only.	

The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
We do not see any reason why the method used to establish Ratings/Limits would be different in the near-term and longer-term horizons. The time horizon necessary to fund, plan and construct facilities is much longer than 1 to 2 years. Unacceptable system performance needs to be identified five to ten years in the future to allow for building facilities to solve these issues. As for alternative language, we would just strike the words “of the Near-Term Transmission Planning Horizon” from the requirements.	
Likes 0	
Dislikes 0	
Response	
Nothing in the SDT’s choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the	

difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES believes there is insufficient technical reason to exclude the Long-Term Transmission Planning Horizon from Requirements R1-R3. The use of different Facility Ratings, System steady state voltage limits, and stability performance criteria between the Near-Term and Long-Term Transmission Planning Horizons has the potential to be problematic. To ensure consistency with Reliability Standard TPL-001-4, which includes both the Near-Term and Long-Term Planning Horizons in the Planning Assessment, LES recommends the following change to R1-R3: "Each Planning Coordinator… used in its **annual** Planning Assessment are equally limiting…".	
Likes 0	
Dislikes 0	
Response	
Nothing in the SDT's choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the	

difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We don't see any reason why the method used to establish Ratings/Limits would be different in the near-term and longer-term horizons. The time horizon necessary to fund, plan and construct facilities is much longer than 1 to 2 years. Unacceptable system performance needs to be identified five to ten years in the future to allow for building facilities to solve these issues. As for alternative language, we would just strike the words "of the Near-Term Transmission Planning Horizon" from the requirements.	
Likes 0	
Dislikes 0	
Response	
Nothing in the SDT's choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only. The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there	

were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
We are confused by the question as posed. The proposed revisions provide a planning horizon of Long-term Planning for R1 through R3.	
Likes 0	
Dislikes 0	
Response	
The proposed standard, FAC-015-1, uses language in Requirements R1, R2 and R3 which reference the "Planning Assessment of the Near-Term Transmission Planning Horizon", not the Long-Term Transmission Planning Horizon. The question posed asked if the commenter agrees with the noted Time Horizon use (Near-Term) or not for the purposes of Requirements R1 through R3.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	

Answer	Yes
Document Name	
Comment	
We think that It is unnecessary and less worthwhile to include the Long-Term Planning Horizon (6 - 10 years in the future) because the future system assumptions (load, generation, transfers, etc.) are more uncertain and speculative than the Near-Term Planning Horizon. So, the results would be less useful and subject to change than the Near-Term Planning Horizon results.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agreed with the SDT that Planning Assessments in scope for these requirements should be limited to the Near-Term Transmission Planning Horizon. PCs are already required to share their results with their RCs, per NERC Reliability Standards IRO-017-1. Sharing similar results from Planning Assessments that are analyzed over a longer time period may not readily benefit the RC looking to develop Operating Plans that alleviate SOL Exceedances.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We concur with that statement as this is the closest Planning time horizon to that of Operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
With the exception of planned facility upgrades, we are unaware of why facility ratings, steady-state voltage limits, and stability performance criteria would be different in the Long-Term vs. Near-Term Planning Horizons and would need to be coordinated with the Reliability Coordinator. Therefore, for the Eastern Interconnection, limiting the coordination from the Near-Term Planning Horizon with the Operating Horizon to a discussion of changed facility ratings should be adequate to maintain reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, and concur with your assessment that there should be few instances of differences in Facility Ratings, System steady state voltage limits, and stability performance criteria.	

Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Entergy agrees with the rationale that the time period of 1 to 5 years the assumptions tend to be more certain.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that the Planning Assessments should be limited those for the Near-Term Transmission Planning Horizon, as it is very difficult to make an assessment on stability in years 6-10. We agree that this should only apply to the Near-Term Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Once these facilities move into the Near-Term horizon, 5 years provides sufficient time to identify thermal constraints in the same manner as they would be seen operationally and develop appropriate Corrective Actions. The Near Term horizon is more than enough time to identify constraints and prepare any needed operational strategies for scenarios that may be candidates to be declared an IROL by the RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Comment	
Limiting to the Near-Term assessment is fine. However, the Manitoba Hydro Planning Coordinator does not typically change the limits/criteria/ratings between the Near-Term and Long Term horizons. The exception would be Facility Ratings where a modification occurred (Corrective Action Plan installed) or possibly a facility rating methodology changed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The Facility Ratings, voltage limits, and stability criteria (SOLs) should be limited to Near-Term Transmission Planning Horizon. The system conditions and uncertainty beyond Near-Term Transmission Planning Horizon are better suited for large capital projects which require extensive licensing. Unnecessary engineering and licensing may occur if more restrictive SOLs are required for Long Term Transmission Planning.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
AZPS agrees that it should be limited to Planning Assessments of the Near-Term Transmission Planning Horizon and further recommends that it should be limited to only studies for years 1 to 2. The Near-Term transmission planning horizon covers years 1 to 5 and is much longer than the operating horizon. Requiring SOL methodology limitations to be used for years 1 – 5 of the Near-Term Planning Horizon could be problematic and is unnecessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
While we agree with the principle since the near term planning horizon is more aligned with operations horizon, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements in existing standards or modifying existing standards. R1 is covered in MOD-032-1. R2 and R3 are already addressed in TPL-001-04.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please recognize that the SDT saw the need for this review of Facility Ratings, System steady state voltage limits, and stability performance criteria between the Planning and Operating Time Horizons. Our SAR did not allow for changes in the standards which you note.	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
We disagree with the implementation of FAC 15-1. The Facility Ratings, System steady state voltage limits, and stability performance criteria used in the near term are not different from those used in the long term.	

Likes 0	
Dislikes 0	

Response

Nothing in the SDT's choice (of a comparison using the Near-Term Planning Horizon) precludes a Planning Coordinator or Transmission Planner from using consistent Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments across all Planning Horizons. The SDT wanted to only compare the Facility Ratings, System steady state voltage limits, and stability performance criteria for use in Planning Assessments of the Near-Term Transmission Planning Horizon due to its best comparability to the Operations Horizon. In addition, the SDT recognized that the Long-Term Planning Horizon may include more differences in Facility Ratings (due to changes in facilities to mitigate issues found in past Planning Assessments), and only wanted Planning Coordinators and Transmission Planners to have to provide a technical rationale for those differences within the Near-Term Planning Horizon only.

The expectation is that System steady state voltage limits and stability performance criteria should be the same in the Near-Term and Long-Term Transmission Planning Horizons, as well as in any Operations Horizon. If they are not, there should be a technical reason for the difference. The same holds true for Facility Ratings; they would expect to be the same among all Horizons for the same facility, but if there were a change in the facility (due to a planned change as a need identified in a Planning Assessment), then there would be a technical reason for the difference.

13. In Requirements R1 – R3, the SDT is proposing to allow a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology. Do you agree that this provides adequate flexibility (in the rare circumstances when less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria must be utilized; e.g., up-rating a line in a future project) without compromising reliability? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

: It makes sense to require PC/TPs to use the same "type" of Facility Ratings and Voltage Limits as the RC/TOP (i.e. if the TOP is operating to 20-minute emergency ratings, the TP/PC shouldn't be planning to 60-minute emergency ratings). If that is the intent, then this requirement should be included in the TPL-001 standard rather than in this separate FAC-015 standard. The language I would put in the TPL standard would look something like: "Each Transmission Planner and Planning Coordinator shall use the same or a more conservative category of Facility Rating (i.e. using the same emergency rating duration, or using only normal ratings) as used by the TOP/RC in operations."

The language of the proposed requirements implies that the RC will be the arbiter of which planned projects can be included in planning cases, which does not make sense. If the intent is make sure the RC is aware of these planned projects, the language should be changed (perhaps in a separate

requirement) to something like: "the PC/TP shall inform its associated RC of any planned projects that result in changes to Facility Ratings, System Voltage Limits or Stability Limits used in the planning horizon." If the drafting team sees a need to set the terms under which a project can be included in a TPL planning case, that should be included in the TPL-001 standard, not decided on a case-by-case basis by the RC.

In the case of Stability Criteria, TPL-001-4 and WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria.

Likes 0	
Dislikes 0	

Response

Regarding the example you cited in your first paragraph, planning to a 60-minute Emergency Rating by a PC/TP would be an example of those entities using a more limiting rating that the RC/TOP who is operating to a (higher) 20-minute Emergency Rating. Your point about "same type" of ratings is well taken and the SDT agrees.

The intent of FAC-015-1 is not to allow the RC to dictate what projects go into planning cases. It is intended to provide for the coordination of Facility ratings and voltage/stability limits between planning and operations.

FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

R1: The Facility Ratings are coordinated through the MOD-032-1 model development process. Modeling differences from year to year are documented but not between each series of models. The RC is regularly updating Facility Ratings to perform operational and real time studies. The Planning Models are made annually with assumptions made on in-service dates. A particular RC model could easily be out-of-sync with a particular PC model on certain pieces of equipment, however there should be no reliability gap as a result. If the Facility Ratings used by the RC are different from the Year 1 planning model, perhaps the RC should provide a technical justification to the PC instead? This seems to be a lot of work for minimal if any reliability gain.

R2: The PC has documented steady state voltage criteria as required by TPL-001-4 R5. The Transmission Operator fundamentally sets the steady state voltage limits on each BES bus as per NERC FAC-014-3 R2 and NERC FAC-011-4 R3.1. It makes more sense for the PC to coordinate with the Transmission Operator(s) within the PC area to ensure that limits/criteria are coordinated and exceptions noted. This would be an

easy task that it is already performed in Manitoba. The PC criteria is documented in the Transmission System Interconnection Requirements document (created to be compliant with FAC-001) and exceptions developed by the Transmission Operator are noted in a referenced Normal Operating Procedure. R3: The PC has documented steady stability criteria as required by TPL-001-4 R4 and R5. The Transmission Operator sets the stability criteria as per NERC FAC-014-3 R2 and NERC FAC-011-4 R4.1. It makes more sense for the PC to coordinate with the Transmission Operator(s) within the PC area to ensure that limits/criteria are coordinated and exceptions noted. This would be an easy task that it is already performed in Manitoba. The PC criteria is documented in the Transmission System Interconnection Requirements document (created to be compliant with FAC-001). Manitoba Recommends removing R1 and having the coordination in R2 and R3 occur between the PC and relevant Transmission Operator(s) that are responsible for the PC area if needed. Alternatively, the criteria developed by the PC under TPL-001 could be shared with the Transmission Operator.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees that MOD-032 provides the process for coordinating Facility Ratings in planning models. The rationale for R1 cites this as well. Additionally, the SDT is considering language revisions to add clarity on Facility Ratings assumptions. The RC sets the SOL criteria the TOP must adhere to. The SDT believes the coordination between planning assumptions and operation assumptions should include the RC's SOL Methodology.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Suggest adding the phrase "at the same assumed ambient temperature(s)" after the term "Near-Term Transmission Horizon" in the first sentence of R1. The purpose is to make clear that the use of dynamic ratings based on ambient conditions in Operations for thermal ratings can be utilized and that the correlation of the Planning Coordinators Facility Ratings and the Facility Ratings associated with the Reliability Coordinator can be at a discrete small set of ambient temperatures.

Likes 0	
Dislikes 0	

Response

This point is well taken. The SDT is considering revisions to clarify R1.

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	No
Document Name	

Comment

It makes sense to require PC/TPs to use the same "type" of Facility Ratings and Voltage Limits as the RC/TOP (i.e. if the TOP is operating to 20-minute emergency ratings, the TP/PC shouldn't be planning to 60-minute emergency ratings). If that is the intent, then this requirement should be included in the TPL-001 standard rather than in this separate FAC-015 standard. The language I would put in the TPL standard would look something like: "Each Transmission Planner and Planning Coordinator shall use the same or a more conservative category of Facility Rating (i.e. using the same emergency rating duration, or using only normal ratings) as used by the TOP/RC in operations."

The language of the proposed requirements implies that the RC will be the arbiter of which planned projects can be included in planning cases, which does not make sense. If the intent is make sure the RC is aware of these planned projects, the language should be changed (perhaps in a separate requirement) to something like: "the PC/TP shall inform its associated RC of any planned projects that result in changes to Facility Ratings, System Voltage Limits or Stability Limits used in the planning horizon." If the drafting team sees a need to set the terms under which a project can be included in a TPL planning case, that should be included in the TPL-001 standard, not decided on a case-by-case basis by the RC.

In the case of Stability Criteria, TPL-001-4 and WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria.	
Likes 0	
Dislikes 0	
Response	
Regarding the example you cited in your first paragraph, planning to a 60-minute Emergency Rating by a PC/TP would be an example of those entities using a more limiting rating that the RC/TOP who is operating to a (higher) 20-minute Emergency Rating. Your point about "same type" of ratings is well taken and the SDT agrees. The intent of FAC-015-1 is not to allow the RC to dictate what projects go into planning cases. It is intended to provide for the coordination of Facility ratings and voltage/stability limits between planning and operations. FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Although the NSRF agrees there may be cases where this flexibility is necessary, there is no criterion to determine what acceptable technical justification is. Nor does the standard identify who it is that determines that the technical justification is acceptable. This leaves ambiguity in the proposed requirements. The requirements need to clearly spell out which entity is responsible for determining when it is appropriate for less limiting criteria to be used in planning evaluations. As it is the real-time operators who will have to operate the system as designed, we believe the RC should have the final say as to whether the justification is appropriate or not.	

Likes 0	
Dislikes 0	

Response

The SDT is considering revisions to clarify the issue of exceptions allowed by the requirements. It is important to note the NERC Functional Model does not give the RC authority over planning entities.

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

See the response to Q16.

Likes 0	
Dislikes 0	

Response

See answer to Q 16.

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

For consistency.

Likes 0	

Dislikes 0	
Response	
Apologies but this comment is not clear and thus the SDT cannot address your potential concern.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
R1-R3 should provide Transmission Planner and not only Planning Coordinator the opportunity to provide a technical justification for 'different' Facility Ratings, System steady state voltage limits, and stability performance criteria to its Reliability Coordinator. The alternative language should have an addition of "Transmission Planner or" as follows: "[…]If the **Transmission Planner or** Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator."	
Likes 0	
Dislikes 0	
Response	
The initial posting of FAC-015-1 allowed for the technical justification from the TP to the PC (R5). The SDT is considering modifications to the language in R1 – R3.	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No

Document Name	
Comment	
Please refer to the comments submitted by the SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Answer provided to SPP Standards Review Group comments	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

While CHPD appreciates the nod to flexibility by allowing the Planning Coordinator to use different criteria, with justification to the Reliability Coordinator, CHPD disagrees with the statement that this will be a rare circumstance. As stated above, CHPD feels a better tool would be for the Reliability Coordinator and Planning Coordinator to exchange methodologies and ratings assumptions / practices, and to have the ability to comment to each other with technical concerns. Alternative language for R1-R3 could be something to the effect:

R1. The Reliability Coordinator shall provide its methodology, performance criteria, and ratings assumptions to each Planning Coordinator in the Reliability Coordinator's area

Each Calendar Year

90 days prior to a change

R2. The Planning Coordinator shall provide its methodology, performance criteria, and ratings assumptions to each Reliability Coordinator in the Planning Coordinator's area Each Calendar Year 90 days prior to a change R3. If the (Planning Coordinator or Reliability Coordinator) receive technical comments in writing from the (Reliability Coordinator or Planning Coordinator), the (Planning Coordinator or Reliability Coordinator) shall respond to those comments within 30 days.	
Likes 0	
Dislikes 0	
Response	
The suggested language for R1 would be more appropriately included as a suggestion for FAC-011 revisions. TPL-001 requires this type of communication (as proposed in your suggested R2 & R3) of the Planning Assessment. As such, the SDT did not include this type of language in the draft of FAC-015.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Please see our comments for question number 6 regarding feedback loops.	
Likes 0	

Dislikes 0	
Response	
See response for question 6.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
This would place too much burden on both the PC and TP. Per FAC-008-3, Facility Ratings are calculated by the TO and communicated to the TP and TOP (typically all within the same organization) and to the PC and RC. These same ratings are used throughout both the Near-Term and Long-Term Planning Assessments unless a planned project causes them to change or a project that is under construction goes in service. Coordination occurs today and should be allowed to continue without strict dictates on exactly how each organization will perform their work. The standard should only specify the end objective and not the process to achieve that objective.	
Likes 0	
Dislikes 0	
Response	
The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. FAC-015-1 does not require additional simulations beyond what is already required by TPL-001. It does require planners to use Facility Ratings and System voltage/stability performance criteria that are consistent with what is used in the operation of the applicable System or document any exceptions.	

Additionally, FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the proposed FAC-015 or a modification to existing standards.

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

With the exception of planned facility upgrades, we are unaware of why any technical justification would be required by the PC to the RC. Conversely to what is stated in the question, we do not believe that facility upgrades are rare circumstances and compromise reliability.

Furthermore, we see nothing in the NERC Functional Model that would allow the PC and RC to develop or establish system performance criteria as part of their defined roles, or to establish performance criteria that could be more restrictive than the criteria provided by the Transmission Owners and Transmission Planners. Standard TPL-001-4 dictates system performance requirements. PC and RC cannot arbitrarily decide to come up with new, more restrictive system performance criteria.

We are also concerned that requirements R1 through R3 allow for no input from the Transmission Planners regarding the development of any performance criteria established by the Planning Coordinator. Requirement R4 then requires the PC to simply hand-down its criteria to the Transmission Planner without any input as to whether the criteria are reasonable or whether meeting the criteria is feasible. At a minimum, requirements R1 through R3 need to recognize that the development of any PC based system performance criteria has to be a collaborative effort between the PC and the TPs and the Transmission Owners. Any tightening of performance criteria will likely require capital investment and we need to hear from the Planning Coordinators as to why the planned system needs to meet the new, more stringent reliability requirements.

Requirements R1 through R3 require the Planning Coordinator to provide a technical justification to the Reliability Coordinator for using less limiting ratings, voltage limits, or performance criteria. We can see that some equipment ratings can change from year to year, and perhaps the corrective action plans should also be provided for those parts of the system that have been or are planned to be upgraded. However, we disagree with the approach proposed by the SDT for the voltage limits and stability criteria, and instead believe that the drafting team needs to have the Reliability Coordinator provide a technical basis to the Planning Coordinator and the Transmission Planners regarding why more

limiting ratings and performance criteria should be required in planning assessments. As any tightening of ratings and performance criteria will likely require capital investments, we need to hear from the Reliability Coordinators as to why the system as provided/planned needs to meet the new, more stringent reliability requirements.	
Likes 0	
Dislikes 0	
Response	
In the initial posting of FAC-015-1, the intent was that a "technical justification" would be required, for example, in instances where a PC planned to a 15 minute Emergency Rating when the RC's methodology only allowed the for a 30 minute Emergency Rating to be used in the operation of the System. This would result in planning studies that used less restrictive Facility Ratings than what is used to operate that system. FAC-015-1 is not intended to allow the RC to dictate criteria on planning entities who are not under the authority of the RC. The intent is to ensure the system is planned in a manner that is conducive to the reliable operation of that system. If planning entities use less limiting criteria, the standard does require documentation as to why less limiting criteria were used but does not give the RC authority to accept or reject that documentation. The PC to TP communication does not imply the process of determining performance criteria or modeling assumptions is not a joint effort by the PC and the TP. The rationale for R1 even speaks to the joint effort required by MOD-032-1 as being the appropriate mechanism for the coordination of Facility Ratings in planning models. The SDT is revising the language in the requirements to add clarity regarding exceptions to R1 – R3 and to simplify the language around the PC/TP communication path.	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	

For the reasons noted in the response to Question 11, the ISO does not agree with the implementation of FAC-015. However, if it is implemented, we support allowing a PC to provide a technical justification to its RC for using less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in its RC's SOL Methodology.

We request the term "Facility Ratings" in the requirement and throughout the standard be replaced with something like "applicable Facility Ratings duration criteria".

"In the case of Stability Criteria, TPL-001-4 and TPL-001-WECC-CRT-3.1 provide pretty explicit criteria for planning assessments. If these are not consistent with the RC requirements, that should be addressed within those standards. The TP/PC should not need to comply with two different sets of stability criteria."

Likes 0	
Dislikes 0	

Response

The response to your comment on question 11 applies here as well.

In addition, FAC-015 is intended to bound the criteria used in studies done in support of TPL-001. If there are differences in criteria between planning and operations, the standard requires the documentation of these differences.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

There needs to be language defining who decides that the technical justification is acceptable.

Likes 0	
Dislikes 0	

Response	
The SDT is considering revisions to clarify the issue of exceptions allowed by the requirements. It is important to note the NERC Functional Model does not give the RC authority over planning entities.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We agree with the statement in principal but the Facility Rating provided by the equipment owner that is applicable for the year of the study (which may be less restrictive) should still be the one that is used. The language in the requirement should address this.	
Likes 0	
Dislikes 0	
Response	
The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

PNMR believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA. Instead of allowing for exceptions, PNMR suggests that the RC, TOP, and PA should jointly develop system performance criteria.

Likes 0	
Dislikes 0	

Response

The potential for "gaps" between planning and operations exist today. The addition of FAC-015 will, at a minimum, facilitate recognition of these "gaps" where they exist. The SDT did not take the route of requiring the PC to jointly develop criteria with TOPs and RCs due to the fact that the PC is not under the jurisdiction of the RC and the RC is not under the jurisdiction of the PC. Therefore, there would be no entity that had the authority to effectively force a set a common criteria on the other should joint efforts fail.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

In most situations, proposed R1-R3 provides adequate flexibility without compromising reliability; however, it raises a question:

If the RC needs to lower an SOL below the Facility Rating in real-time due to clearance issues, how does the PC monitor SOLs to determine if an SOL has gone lower than the Facility Rating, necessitating technical justification?

Likes 0	
Dislikes 0	

Response

When issues occur in real-time such as the given example, it is not the PC's responsibility to monitor these types of events. However, if a de-rate is expected to go on indefinitely, planning models should be updated with the lower Facility Rating as it is a change to an existing Facility that must be modeled as required by TPL-001-4, Requirement R1.1.3.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
In the event planned transmission system upgrades exist, the PC would often need to use less limiting Facility Ratings for those facilities. The SDT should consider including a firm exclusion of transmission system upgrades for FAC-015-1 R1 to avoid unnecessary documentation for a frequent and commonly understood justification. ERCOT suggests the following revision to achieve this purpose: Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that, ***for all Facilities other than those with planned transmission upgrades***, Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. ****Please refer to the attached comment form for redlined language.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	No
Document Name	
Comment	
PCs are already required to provide the results of their Planning Assessments to impacted RCs, per NERC Reliability Standards IRO-017-1. The inclusion of technical justifications for using less limiting SOLs would then be included in addition to these results. We caution the SDT that the target audience of a RC's SOL Methodology are TOPs, not PCs. TOPs use this methodology to determine applicable owner-provided Facility Ratings, System Voltage Limits, and stability limits that can be used in operations. We feel this creates a process gap that should be addressed by requiring the RC to include, in its SOL Methodology, a method for PCs to determine applicable owner-provided Facility Ratings and System Voltage Limits in their Planning Assessments.	
Likes 0	
Dislikes 0	
Response	
The SDT understands the intent of the RC's SOL Methodology and the target audience. As such, the RC including a method for PC's to determine applicable owner-provided Facility Ratings and System Voltage Limits would not be appropriate additions to this methodology since the RC has no jurisdiction over a PC per the NERC Functional Model. The SDT agrees that one method for communicating the technical justification would be to document it in the Planning Assessment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
While we agree with the principle, BPA does not see a need for a new standard. The objective could be better accomplished by including the requirements to existing standards or modifying existing standards. MOD-032-1 and TPL-001-4 should be modified to address.	

Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. Based on feedback from KEY STAKEHOLDERS, this level of coordination is necessary and needs to be captured in either in the proposed FAC-015 or a modification to existing standards. Currently, the SAR for this project does not allow for the modification of other standards such as MOD-032 & TPL-001.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The proposed process for exceptions is adequate because it ensures visibility of these exceptions to the Reliability Coordinator. The transmission system is nuanced and providing this flexibility is important granted that the affected parties are involved (such as the RC).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The increased visibility is a primary driver for the inclusion of the technical justification.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Reclamation supports the use of less limiting Facility Ratings, System steady-state voltage limits, and stability performance criteria than those specified in the RC's SOL Methodology when appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
There may be circumstances where there is a technically justifiable reason for using less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in accordance with (or described in) the RC's SOL Methodology. However, if the RC does not agree with the technical justification provided by the PC, the RC should have the authority to refute the justification which would then require that the stipulations in the RC's SOL Methodology would prevail.	
Likes 0	
Dislikes 0	
Response	
The RC has no jurisdiction over a PC per the NERC Functional Model.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that the proposal provides adequate flexibility, however, we request further clarification from the drafting team on how question 11 above, works in concert with question 13.	
Likes 0	
Dislikes 0	
Response	
The focus of question 11 was on the requirement that Facility Ratings, voltage limits, and stability criteria used in the production of the Planning Assessment should be bounded by the same criteria the RC dictates in the operation of the System. Question 13, is focused on the adequacy of the technical justification and whether it will provide the appropriate flexibility for planning entities should they have reasons to use less limiting criteria.	

Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Entergy agrees with allowing the PC to provide a technical justification. Not all situations can be covered and there may be extenuating circumstances where it is necessary to use less limiting ratings.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
AECI agrees that this approach provides adequate flexibility. A Registered Entity may encounter circumstances where there is a technically justifiable reason for using less limiting Facility Ratings, System steady-state voltage limits, and stability criteria than those established in the Reliability Coordinator's SOL Methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
A sound technical justification may indeed be appropriate in certain cases and this flexibility is well captured by the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
However, the SDT should include the Transmission Planner as an entity that can also provide lower facility ratings and limits as they are required under TPL to establish those limits for facilities in their purview. Note: ERCOT does not support this response.	
Likes 0	
Dislikes 0	
Response	

This concept was captured in Requirement R5 of the original posted version of FAC-01—1. The SDT is modifying the language in FAC-015-1 to clarify the PC/TP communication.	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Reference MOD-032-1, attachment 1, "items marked with asterisk indicate data that vary with system operating state or conditions." In this case, the new “system operating state” is the particular future year under study which should incorporate all anticipated topology and rating changes for that year. These topology and rating changes may have been added to upgrade an existing SOL.	
Likes 0	
Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions.	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Reference MOD-032-1, attachment 1, "items marked with asterisk indicate data that vary with system operating state or conditions." In this case, the new “system operating state” is the particular future year under study which should incorporate all anticipated topology and rating changes for that year. These topology and rating changes may have been added to upgrade an existing SOL.	
Likes 0	

Dislikes 0	
Response	
The SDT is revising the language in Requirement R1 and the associated rationale to add clarity regarding allowable exceptions.	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
We think that although the circumstances for more limiting SOLs may be rare, it is wise to include provisions for addressing them in case they would occur.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

14. Do you agree that the information identified in Requirement R6 is necessary for each impacted RC and TOP to properly evaluate instability, Cascading, or uncontrolled separation identified in planning assessments for use in establishing stability limits and IROLs in the operations horizon? If not, please explain and provide alternative language.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	

We disagree that Near-Term Transmission Planning Horizon and Transfer Capability Assessments will necessarily be useful for establishing stability limits and IROLs in the operating horizon because the basis for planning horizon assessments [transmission planning system models (e.g. firm loads, firm transfers, and generation dispatch) and applicable contingencies] are quite different from the basis for operating horizon assessments. It also seems that the burden on the PCs to prepare the required information packages for potentially impacted RCs and TOPs will not be commensurate with the limited benefit that it may provide to RCs and TOPS. It would be more reasonable, clear cut, and pose less compliance risk to require PCs to simply provide their Near-Term Transmission Planning Horizon and Transfer Capability Assessments to the RCs and TOPS within and adjacent to their area. The RCs and TOPs would then decide from themselves whether any information in these documents may be interest or impact them.	
Likes 0	
Dislikes 0	
Response	
The SDT discussed these issues at length when developing the language. It was the consensus of the SDT that the information provided through FAC-15-01, R6 (now R4 in the revised FAC-015) is potentially of great operational value to RCs and TOPs. Since the focus of the requirement is on those instances of instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment, those types of system performance are serious enough to warrant the provision of the information as described in the requirement. The SDT noted that current Near-Term Transmission Planning Horizon or its Transfer Capability assessments do not necessarily provide the desired information in an easy to find fashion. The SDT further determined that the serious potential consequence of these types of system performance warranted the addition of the requirement such that the RCs and TOPs could easily determine if there was a potential that the instances found in planning analyses could occur while operating the system. The SDT does not agree that the value of the information is not commensurate with the preparation effort to collect and provide the information. Given the potential reliability benefit (identification and preclusion of IROLs), we do not believe consideration of compliance risk is appropriate for consideration here given the limited effort involved.	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	No
Document Name	
Comment	
FAC-15-1 Requirement R6 is a step in the right direction. However, FAC-15-1 should address that Planning Assessments and Operations studies for derivation of SOLs and IROLs are not of the same scope in terms of number of facilities considered out of service. Therefore simply enforcing that the performance criterion used in the Planning Assessment be more restrictive than that used in Operations does not materially improve the operability of planned facilities. The scope of the studies in the Operations Horizon should be increased to bridge this gap through Requirements in FAC-11-4 and FAC-14-3.	
Likes 0	
Dislikes 0	
Response	
The revised FAC-011-4 standard addresses, at length, the SOL methodology. The revised R4 requires definition of multiple criteria for determination of stability limits. The SDT believes there is no need to further address studies in Planning or Operations, but rather focus on the information that can be gleaned from existing Planning analyses. One of your statements is factually incorrect; FAC-015-1 does not require the performance criteria used in Planning studies to be more restrictive; it has to be equal or more restrictive than that used in Operations, or a technical justification why is it not has to be provided. Given this, there is room for explained differences in Planning and Operations criteria. The SDT recognized that the scope of planning and operating stability studies can be, and are often, different. The scope of the requirement focused on conveying potentially critical information to the RC and TOP in an efficient manner. The SDT believes it is the responsibility of the RC to describe in its SOL methodology the breadth of work required to perform stability studies, and the SDT does not presume to know what expanded scope of stability work should be included by every RC and their TOPs.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	

Comment	
This would place too much additional compliance burden on the PC. If the RCs and TOPs believe that this information is important for them to obtain, a SAR should be opened to add this to the TPL-001 standard or at least the IRO-017 standard verses creating another new standard that requires the PC to provide additional information from the TPL standard to the RC and the TOP.	
Likes 0	
Dislikes 0	
Response	
The existing standard already has the PC providing information to the RCs for those multiple contingencies that result in stability limits (FAC-011-3, requirement 6 and its subparts). The SDT discussed the value of the information provided through this requirement and believed that the information was inadequate for the needs of the RC, especially in light of FERC's renewed focus on IROLs. The SDT determined that the information sought in the proposed R6 was the minimum the RCs and TOPs need to quickly determine if there are any contingencies, single or multiple, that result in system instability, Cascading or uncontrolled separation. This information should already exist in the Near-Term Transmission Planning Horizon or its Transfer Capability assessments. Since this information would then be used to determine IROLs, which are determined using the RC's SOL methodology, the SDT believed this information was appropriate for inclusion within an FAC standard and could not wait to addition of a SAR and potential inclusion in another standard.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Because UFLS and UVLS relays are permitted to trip load beyond P2.1 contingencies in the Planning Assessment and will trip as needed to help stabilize the simulation, it is not possible for FAC-015-1 R6.4 to be achieved because the simulation will not reach the point of instability, Cascading, or uncontrolled separation with the relay action present in the simulation. In order to make this determination (whether there would have been instability, Cascading, or uncontrolled separation if they had not tripped), an entity would have to run a second set of simulations blocking all UFLS and UVLS relays from tripping. The system performance could then be assessed and the information in FAC-015-1 R6.4 related to UFLS and UVLS relays could then be provided. As these additional simulations would represent additional burden to the	

work performed under TPL-001-4, CHPD feels that the proposed FAC-015-1 R6.4 should have the items related to UVLS and UFLS removed from the criteria. If this is a reliability objective, it should be addressed under the TPL-001-4 standard.	
Likes 0	
Dislikes 0	
Response	
While the SDT agrees that the explicit modeling of the actions of the UFLS and UVLS relays may preclude clear identification of instances of instability, Cascading and uncontrolled separation in stability assessments, the SDT does not believe all planning entities include such models in all of the stability models. Furthermore, an RC, per FAC-011-4, Part 4.7, state explicitly that under-frequency load shedding (UFLS) and Under-voltage Load Shedding Programs are not allowed in the establishment of stability limits. This requirement is based upon long-standing FERC rulings stating that these programs are Given that, then those dynamic models and resulting studies without explicit UFLS and UVLS modeling could provide the necessary information requested in R6 (now R4 in the revised standard). In addition, for those entities that do model UFLS and UVLS, they could construe requirement FAC-011-4, R4.6 to indicate that any actuation of UFLS or UVLS for normal criteria contingencies respected by the RC or TOP as being an indication of potential instability, Cascading or uncontrolled separation. As such the SDT is not requiring any additional simulations on the part of planning entities. Finally, the TPL-001-4 standard is not the only standard with a reliability objective, so it is not the only potential home for a requirement such as FAC-015-1, R6 (now R4).	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Need more specific with property data especially “switching data”.	
Likes 0	
Dislikes 0	

Response	
The SDT needs more information to respond to your comment. We searched through the proposed standards and did not find any occurrence of the phrase "switching data". Can you describe what you mean by "switching data" and where you find the reference, or implied reference, in the proposed standards?	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. The SDT recognizes that assessments and analyses in Planning and Operations may have differences. The concern noted, with the removal of FAC-010, and the underlying reasons why the FAC-010 and FAC-011 standards first came into being, was to have a system planned that could then be operated. The SDT, with observer participation, further noted that if fundamentally different assumptions were used (for thermal, voltage or stability limits / criteria) between planners and operators, then they might be poor correlation between issues found and resolved by planners, and those found and requiring action by operators. With the removal of FAC-010, the value to reviewing consistency between limits and criteria used in planning and operating the system became obvious. The SDT recognizes that neither the PC nor RC has jurisdiction over the other entity for their industry responsibilities (planning and operating, respectively). However, it is the RC, as the ultimate operating authority, that needs to know that the limits it uses to operate the system (based upon thermal ratings, voltage limits and stability criteria) and how they compare against limits used when the system is planned.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No

Document Name	
Comment	
The use of the term "instability, Cascading, or uncontrolled separation" as stated in R6 may not be clear to all that the purpose is for the Planning Coordinator to alert the RC to scenarios that have the potential to be categorized as IROLs in the Operations arena based on the RC's SOL methodology. Suggest rewording R6 to: "Each Planning Coordinator shall communicate scenarios that demonstrated IROL type conditions such as instability, Cascading, or……." However, it should be made clear that the RC would make the determination if it would be considered an IROL based on the RC's SOL methodology	
Likes 0	
Dislikes 0	
Response	
The SDT purposefully chose the terms included in the proposed standard so that the PC would focus on their assessment and determination of which results met the "instability, Cascading or uncontrolled separation" characterization without having to use any SOL methodology. The RC has the responsibility to review the information provided, and utilize the information as it sees fit, which would include application of their SOL methodology as applicable.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
R6 is better located in TPL-001-4 or FAC-013-2. The current language states that "any" instability, Cascading or uncontrolled separation should be communicated. Does the RC need or want to know about extreme disturbances or only P1-P7 events? It makes more sense to share the Planning Assessment and Transfer Capability assessments to the RC as part of the relevant standards.	
Likes 0	
Dislikes 0	

Response	
The SDT's scope and the initiating SAR do not include revisions to either TPL-001-4 or FAC-013-2. The SDT does agree that a later drafting group could take requirement R6 (now R4 in the revised FAC-015-1) and place it in TPL-001-4. It should be noted, though, that the entirety of the requirement is required, including explicit communication from the PC to the RC of the requested information. The SDT discussed at length the information conveyed today in planning assessments and agreed that while the requested information may be in all planning assessments, it is commonly not easily found and not included in the level of detail noted in requirement 6. The RC does want to know about any PC stability simulation result that has as an outcome of instability, Cascading or uncontrolled separation.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
This requirement is already included in other planning standards, such as TPL-001-4 and IRO-017-1. The objective could be better accomplished by modifying or including specific details of the requirement in existing planning standards. IRO-017-1 requires the TPs and PCs to provide the system assessment to their RC. Any identified instability would be included in the system assessment. The RC is in the best position to inform the TOP in the RC area. TPL-001-4 also requires the PCs and TPs to share the system assessment to adjacent TPs and PCs.	
Likes 0	
Dislikes 0	
Response	
The SDT discussed at length the information conveyed today in planning assessments and agreed that while the requested information **may** be in all planning assessments, *it is not necessarily* in all planning assessments, is not easily found if present, and not included in the level of detail noted in requirement 6. The SDT arrived at the specifics captured in requirement 6 (now R4 in the revised FAC-015-1) after lengthy discussion and debate with regard to its merits. A later SDT may choose to lift this requirement, in its entirety, and place it in TPL-001-4.	
Gladys DeLaO - CPS Energy - 1	

Answer	Yes
Document Name	
Comment	
This data is appropriate for the conditions and timeframes studied in the Planning Assessment. Additional operational analyses may be needed for particular operating conditions that are not part of the conditions and timeframes addressed by the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
PNMR agrees with the information provided in R6. However, PNMR believes that R6 should be included in TPL-001 and should not result in a new FAC standard.	
Likes 0	
Dislikes 0	
Response	
The SDT's scope and the initiating SAR do not include revisions to either TPL-001-4 or FAC-013-2. The SDT does agree that a later drafting group could take requirement 6 (now R4 in the revised FAC-015-1) and place it in TPL-001-4. It should be noted, though, that the entirety of the requirement is required, including explicit communication from the PC to the RC of the requested information.	
James Grimshaw - CPS Energy - 3	

Answer	Yes
Document Name	
Comment	
This data is appropriate for the conditions and timeframes studied in the Planning Assessment. Additional operational analyses may be needed for particular operating conditions that are not part of the conditions and timeframes addressed by the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy request further clarification from the drafting team on the types of events that require communication from the PC to the RC and TOP in R6. The current language states that the PC shall communicate to the RC and TOP of “any” instances of instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment. Does this include “extreme events” as well?	
Likes 0	
Dislikes 0	
Response	
The SDT discussed this issue and determined that the RC does want to know about any PC stability simulation result that has an outcome of instability, Cascading or uncontrolled separation. If the PC performed extreme event simulations that demonstrated one of those three	

results, the RC would want to know, so that if, in the unlikely condition that system were close to one of those end states, the RC would have the benefit of the information for developing an operating plan to preclude the potential instability outcome.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak is especially supportive of subpart 6.4 which requires communication of “Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;” This information is critical for the RC understanding the risks that have been identified and the measures that were taken in the Planning Assessments to address the risk. If this information is not provided, the RC has no way of knowing or understanding what kinds of risks for instability, Cascading, or uncontrolled separation that were identified and successfully mitigated via the measures listed in subpart 6.4. This unawareness can have significant adverse reliability consequences if the associated automatic schemes are rendered unavailable in operations. It is critical that the RC understand the risks that	

were identified and the means by which those risks were mitigated in the Planning Assessment so that these risks can be addressed in operations through the development of Operating Plans.	
Likes 0	
Dislikes 0	
Response	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
In addition to the communication of information to impacted RCs and TOPs, the NSRF believes consideration should be given to including impacted Transmission Planners as well. Although the information is needed primarily by the RCs and TOPs, there is not currently a mechanism to communicate the information back to the impacted TPs for continued awareness. To ensure all parties remain aware of potential issues identified in the assessments, LES recommends the following change to R6: **R6**. Each Planning Coordinator, **in coordination with each impacted Transmission Planner**, shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator.	
Likes 0	
Dislikes 0	
Response	
The SDT has taken your request under advisement for revision of the proposed standard.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes

Document Name	
Comment	
Yes, I think it is appropriate to provide this information. As with above, I think it should be addressed in the TPL-001 standard (as part of R8 perhaps).	
Likes 0	
Dislikes 0	
Response	
The SDT's scope and the initiating SAR do not include revisions to either TPL-001-4 or FAC-013-2. The SDT does agree that a later drafting group could take requirement 6 and place it in TPL-001-4. It should be noted, though, that the entirety of the requirement is required, including explicit communication from the PC to the RC of the requested information.	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
In addition to the communication of information to impacted RCs and TOPs, LES believes consideration should be given to including impacted Transmission Planners as well. Although the information is needed primarily by the RCs and TOPs, there is not currently a mechanism to communicate the information back to the impacted TPs for continued awareness. To ensure all parties remain aware of potential issues identified in the assessments, LES recommends the following change to R6: **R6**. Each Planning Coordinator, **in coordination with each impacted Transmission Planner**, shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator.	
Likes 0	

Dislikes 0	
Response	
The SDT has taken your request under advisement for revision of the proposed standard.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCE recommends one more additional sub-bullet be added such that the PC shall communicate any assumptions of system conditions critical in its identification of instability, Cascading or uncontrolled separation (such as load levels, local generation assumptions, etc.). It is probably obvious but R6 does not currently require it.	
Likes 0	
Dislikes 0	
Response	
The SDT has taken your request under advisement and included it in a revision of the proposed standard. The requirement is now R4 and a new Part 4.4 was included to address your comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes, I think it is appropriate to provide this information. As with above, I think it should be addressed in the TPL-001 standard (as part of R8 perhaps).	
Likes 0	

Dislikes 0	
Response	
The SDT's scope and the initiating SAR do not include revisions to either TPL-001-4 or FAC-013-2. The SDT does agree that a later drafting group could take requirement 6 and place it in TPL-001-4. It should be noted, though, that the entirety of the requirement is required, including explicit communication from the PC to the RC of the requested information.	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
As required by TPL 001-4, planning coordinators implement corrective action plans for any instability, Cascading, or uncontrolled separation identified in planning assessments due to planning events involving single or multiple contingencies. Providing this information to RC may be useful if the corrective action plan is establishing an SOL. On the other hand, providing this information to RC may not be useful if the corrective action plan is transmission development.	
Likes 0	
Dislikes 0	
Response	
The SDT understands your concern and comment and included a revision to the proposed standard to have the PC also document any correction action proposed to resolve instances of instability, Cascading or uncontrolled separation found. The requirement is now found as R4, with a new Part 4.6 included to address your comment.	

15. Do you agree that the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon? If yes, please provide supporting rationale; if no, please explain and provide alternative language.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Reference justification and alternative language proposed as part of the answer for the previous question (i.e., Question 14).

Likes 0	
Dislikes 0	

Response

In the original posted draft of FAC-015-1, Requirement R6 is not limited to IROL-like conditions, but rather applies to all instability risks identified in the Near-Term Transmission Planning Horizon portion of the Planning Assessment. The intent of R6 is to provide a mechanism to ensure instability risks, as well as the appropriate details regarding the instability risk, are properly communicated from planning to operations as previously required by FAC-014-2 Requirement R6. Unlike FAC-014-6 Requirement R6, FAC-015 applies to any instability and not just the risks that are the result of multiple contingency Planning Events.

The SDT, through its proposals for FAC-015-1, FAC-014-3, FAC-011-4, FAC-010-3 (retirement), are eliminating the notion of Planning Horizon SOLs. Therefore, in this construct, the RC's SOL Methodology is the only methodology where SOLs and IROLs are established.

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment	
See the response to Q16.	
Likes 0	
Dislikes 0	
Response	
See response to Q 16.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
FAC-013 (TTC) is not required to have stability criteria, instability criteria, document UFLS or UVLS relay operation, or include Corrective action plans. It is recommended that the reference to the Transfer Capability assessment be removed from the proposed FAC-015-1 R6.	
Likes 0	
Dislikes 0	
Response	
The SDT recognizes that the FAC-013 TCA will vary depending on the entity performing the assessment. Those entities that do not identify stability-related constraints in their TCA would have nothing to report.	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	No
Document Name	

Comment	
Please refer to the comments submitted by the SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Answer supplied to SPP Standards Review Group comment	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
Development of SOLs and IROLs is the appropriate assessment for identifying any instability, Cascading, or uncontrolled separation in the planning horizon that is not mitigated by corrective action plans such as transmission development. TPL001-4 planning assessments require the PC to model peak load and firm transmission services but do not require stressing the system to identify its limits. Transfer Capability assessment is only applicable to tie lines.	
Likes 0	
Dislikes 0	
Response	
The SDT is proposing a new construct where SOLs and IROLs are established in accordance with the RC's SOL methodology only. In this methodology, the types of studies and applicable performance criteria to assess potential instability will be documented. TPL-001-4 also requires sensitivities to be assessed per R2.4.3.	

The Transfer Capability Assessment is performed differently depending on the entity that performs the assessment. It only applying to tie lines is incorrect.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Planning assessments in TPL-001-4 are the appropriate assessments to identify system instability and cascading outages in the planning horizon. However, BPA does not see a need for a new standard. The objective is already addressed by TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001. Additionally, FAC-015-1 R6 is more prescriptive in identifying the details related to potential instability than R4 of TPL-001-4.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes, with the same comment as question 14, with the addition that the FAC-013 standard is the appropriate place to require supplying Transfer Capability Assessment results to impacted RCs and TOPs.	

Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001 and FAC-013.	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Based on the requirements of the new TPL-001-4, the Planning Assessment must identify any Near-Term Transmission Planning Horizon instability, Cascading or uncontrolled separation. The proposed FAC-015-1 R6 correctly references the reliability objective accomplished by TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
FAC-015 R6 supplements TPL-001 R4 in that it specifies a more prescriptive list of details regarding potential instabilities that are not explicitly stated in TPL-001 R4.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Reclamation supports the Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, because these items properly identify potential risks.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
These assessments look at extreme disturbances or non-firm transfers and would be the appropriate studies in the Planning Horizon that would be able to identify instability, Cascading or uncontrolled separation if these concerns existed.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	

Yes, with the same comment as question 14, with the addition that the FAC-013 standard is the appropriate place to require supplying Transfer Capability Assessment results to impacted RCs and TOPs.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001 and FAC-013.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
As the Near-Term Transmission Planning Horizon is the closest to operating horizons, these are the most relevant results to pass on to those responsible for operating the system.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes

Document Name	
Comment	
The assessments applicable to R6 should be reflective of those assessments required by the NERC Reliability Standards. Both Planning Assessments and Transfer Capability assessments are required by the standards. Furthermore, it is possible that when performing Transfer Capability assessments, the first limitation encountered could be a stability limit (i.e., as power is transferred across an interface, a stability limitation is reached before any thermal or steady-state voltage limitation is reached). Because this is an operational possibility, Peak believes that Transfer Capability assessments should be included in R6. Peak also believes Transfer Capability assessments should be included in R1 through R3.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SDT did not include the TCA in R1 – R3 due to the fact that FAC-013 does not have prescriptive requirements outlining the types of planning events to assess and the minimum performance criteria necessary for compliance as TPL-001 does.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	

Response provided to NPCC comment	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
The PC also needs to send the results of its Planning Assessment or Transfer Capability Assessment to its Transmission Planners. This activity should happen before the results are sent to the RC and TOP.	
Likes 0	
Dislikes 0	
Response	
FAC-013 R5 and TPL-001 R8 address PC/TP communication of the applicable assessments.	

Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Note: CAISO does not support this response.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Near-term TP horizon is the closest to operating horizon	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment	
James Grimshaw - CPS Energy - 3	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Answer	Yes
Document Name	
Comment	
One of the purposes of the Planning Assessment is to capture any anticipated instability, Cascading or uncontrolled separation in the near-term and long-term transmission planning horizons.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We concur that both assessments for the Near-term Planning Horizon under TPL-001 and for transfer capability under FAC-013 are appropriate to be used because they are the closest to the Operations Horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	

Answer	Yes
Document Name	
Comment	
PNMR agrees with the assessments as stipulated in R6, however, PNMR believes that R6 should be included in TPL-001 and should not result in a new FAC standard.	
Likes 0	
Dislikes 0	
Response	
FAC-015-1 provides for a level of coordination between planning and operating entities that is currently absent in the body of NERC Reliability Standards. It may be appropriate to include some or all of the requirements of FAC-015 into other existing standards. However, the SAR for this project currently does not allow for the modification of other standards such as TPL-001.	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
One of the purposes of the Planning Assessment is to capture any anticipated instability, Cascading or uncontrolled separation in the near-term and long-term transmission planning horizons.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Planning Assessment of the Near-Term Transmission Planning Horizon and the Transfer Capability assessment, as stipulated in Requirement R6, are the appropriate assessments for identifying any instability, Cascading, or uncontrolled separation in the planning horizon. However, due to BES system topology differences between the Planning Horizon (usually all facility in-service) and Operations Horizon (N-1 or N-1 out of service due to planned or forced) then instability, Cascading, or uncontrolled separation MAY NOT be identified in the Planning Assessment during the Near-Term Transmission Planning Horizon and the Transfer Capability assessment. In the Operations Horizon, the Operating Planning Analyses (OPA) could and may still identify instability, Cascading, or uncontrolled separation due to latest BES modeling to real-time. Also, the requirement for communicating Facility Rating appears to be redundant to the FAC-008 Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with this comment. FAC-015 R6 is intended to replace (and upgrade) the communication of potential instabilities defined in R6 of FAC-014-2. Planning information should be considered appropriately in all OPAs based on the practices/needs of the RC or TOP.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	

Comment	
We think that it is unnecessary and less worthwhile to include the Long-Term Planning Horizon (6 - 10 years in the future) because the future system assumptions (load, generation, transfers, etc.) are more uncertain and speculative than the Near-Term Planning Horizon. So, the results would be less useful and subject to change than the Near-Term Planning Horizon results.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

16. If you have any other comments that you haven't already provided in response to questions 11-15, please provide them here.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT Comments:

Requirements R1, R2, and R3 contain similar language that generally requires the PC's Planning Assessments to use limits that are "equally limiting or more limiting" than the limits established pursuant to the RC's methodology. Each of these requirements also includes a second sentence that appears to allow the PC to use a less limiting value when the PC has a legitimate technical justification for doing so. This second sentence technically contradicts the first sentence. ERCOT proposes additional revisions to clarify that the second sentence operates as an exception to the first sentence.

Also, Requirements R1, R2, and R3 do not specify whether the technical justification provided by the PC must be acceptable to (or accepted by) the RC. In the event of a disagreement between the PC and RC, ERCOT suggests that the rule should be clear as to which entity's determination prevails. ERCOT presumes the RC's determination should prevail in such an event since the RC has ultimate responsibility for overseeing the SOL methodology under proposed FAC-011, Requirement R1. Allowing the PC what amounts to unilateral discretion in establishing limits would undermine the principle that the RC's SOL methodology should generally govern, as reflected in the first sentence of Requirements R1, R2, and R3 in FAC-015. ERCOT therefore recommends revisions to the last sentence of each of these three requirements.

The following revisions reflect both of the changes described above:

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may*** use less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology ***if***, the Planning Coordinator ***provides*** a technical justification ***that is accepted by*** its Reliability Coordinator.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may use*** less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology if the Planning Coordinator ***provides*** a technical justification t***hat is accepted by*** its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, ***except that*** the Planning Coordinator ***may use*** less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology if the Planning Coordinator ***provides*** a technical justification t***hat is accepted by its*** Reliability Coordinator. ****Please refer to the attached comment form for redlined language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the language in Requirements R1, R2 and R3 to address your concerns.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
We ask the SDT to clarify that references to a RC's SOL Methodology is done, as required, per Reliability Standard FAC-011-4. The proposed standard does not make this distinction. The VSLs identified for Requirement R4 do not identify a failure to provide SOL information to requesting PCs.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT is purposely trying to not reference a specific standard in the requirement as that standard could be revised in the future and therefore would require a modification to the standard that is referencing it. The SDT believes that the revised language provides sufficient clarity. The SDT modified the VSL to address your concern.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
National Grid supports the NPCC RSC Group comments. Additional comments for consideration: There is potential area of concern as to why the TP is not included in the PC's communication of any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment FAC-015-1, Requirement R6. Due to lack of consistent definitions/terminology related to definitions of stability concepts regarding both transient stability and small signal-stability (as related to angle stability) as well as voltage stability, the requirement to implement a process related to the stability performance criteria in Requirement R3 (et.al.) is not clearly defined. We suggest revising by using language related to Requirement R4 and R5 in NERC Reliability Standard TPL-001-4, which states that each TP and PC shall have "criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System" and "criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified FAC-015-1 R4 to include the TP as an entity responsible to communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment as well. The SDT understands that the TP would itself get such information from the PC as part of TPL-001-4 R8. The SDT has chosen to retain "stability performance criteria" as this terminology can address both of what is identified in proposed FAC-011-4 R4.1 and TPL-001-4 R5 as well as any differences between the two. The SDT also notes that recently approved *Reliability Guideline: Methods for Establishing IROLs, September 2018* provides additional clarity on stability concepts.

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	
Document Name	
Comment	
Not applicable.	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	
Document Name	
Comment	

This comment is regarding to R4 of FAC-015-1. R4 stated that "Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's". Entities understand that there will need to be two-ways communication between Planning Coordinator (PC) and Transmission Planner (TP). With that said, TPs are much closer to the source of 'Facility Ratings and System steady-state voltage limits'. It would make better sense for TP to provide 'Facility Ratings and System steady-state voltage limits' to PC and consistent to the current practice of TOPs providing 'Facility Ratings and System steady-state voltage limits' to the RC. The R4 as proposed is as having the RC providing 'Facility Ratings and System steady-state voltage limits' to TOPs. As proposed R4, the PC will need to request the 'Facility Ratings and System steady-state voltage limits' from the TP and/or TPs and then the PC will just provide back to the TP/TPs. As drafted, R4 is an effort that involved extra man power and time with no benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the language in Requirements R1, R2 and R3 to address your concerns.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

James Grimshaw - CPS Energy - 3

Answer	
Document Name	
Comment	
FAC-015 Requirement R5 is inappropriately placed outside of the TPL-001 standard. We believe all requirements to perform the Planning Assessment should be housed within the TPL-001 standard to avoid confusion or double work.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under.	
Gladys DeLaO - CPS Energy - 1	
Answer	
Document Name	
Comment	
FAC-015 Requirement R5 is inappropriately placed outside of the TPL-001 standard. We believe all requirements to perform the Planning Assessment should be housed within the TPL-001 standard to avoid confusion or double work.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
FAC-15-1 is a step in the right direction. However, FAC-15-1 should address that Planning Assessments and Operations studies for derivation of SOLs and IROLs are not of the same scope in terms of number of facilities considered out of service. Therefore simply enforcing the performance criterion used in the Planning Assessment be more restrictive than that used in Operations does not materially improve the operability of planned facilities. The scope of the studies in the Operations Horizon should be increased to bridge this gap through Requirements in FAC-11-4 and FAC-14-3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made modifications to FAC-011-4 and FAC-014-3.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
PNMR seeks clarification on the use of single contingency criteria. FAC-011-4 defines a single contingency as a TPL-001 P1 event. In TPL-001 categories P1 and P2 are labeled single contingency. If the RC defines criteria for single and multiple contingency based on FAC-011-4, will the criteria for the single contingency be used for both P1 and P2 events of TPL-001 even though the contingency definition of P2 does not match the single contingency definition in FAC-011-4?	

PNMR believes that FAC-015 has requirements that should be part of the TPL-001 Planning Assessment. Instead of creating a separate standard, PNMR recommends that TPL-001 should be revised to include the new requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please note that usage of "single Contingencies" in R5 of FAC-011-4 was never intended to be the same as its usage within Table 1 of TPL-001-4 and hence made no direct reference to P1 or P2 events. However, in response to your and other comments, the SDT has modified R5 and its sub-requirements to minimize, if not eliminate, any such confusion. Although R5.1.1 is essentially unchanged and continues to closely correspond with P1 event in TPL-001-4, the revised R5.2 and R5.3 are intended to provide more clarity on contingency selection by the RC. In general, R5 in FAC-011-4 is not intended to fully align with Table 1 of TPL-001-4; instead, it is intended to provide reasonable discretion to the RC to select additional (single or multiple) Contingency events regardless of the contingencies in Table 1 of TPL-001-4. The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
The work identified in FAC-015 would be better positioned in the TPL-001 standard. A SAR should be drafted to open the TPL-001 standard to include those required items from this proposed new standard rather than creating a new standard. Coordination of criteria could then be determined between the TP and PC as identified in the TPL-001 standard R7 rather than by this new standard by parties familiar with the information in the local regions.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under. You always have the right to submit a SAR to the NERC Standards Group outlining you proposed modifications.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	
More clarification is needed related to the identification of Facility Ratings. As the Transmission Owners are already obligated to provide planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation). The drafting team should clarify that asset owners typically provide multiple ratings for a given asset based on various conditions and the intent of this standard is to ensure how the RC and PC pick those ratings is consistent. Note: ERCOT does not support this response.	
Likes 0	
Dislikes 0	
Response	
The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. Further, once Facility Ratings are provided by the applicable owner, it is then the responsibility of the RC to determine which of the ratings are to be used in operations and the responsibility of PC and/or TP to determine what ratings are appropriate for long-term planning.	

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The existing FAC-010, FAC-011, and FAC-014 framework provides the required coordination between planning and operation horizons from the planning coordinator perspective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Majority of commenters agree with the SDT's assessment that the proposed new FAC-015-1 standard is needed to enhance the "Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology" compared to the existing FAC-010, FAC-011 and FAC-014 standards plus the existing TPL-001-4 standard. We are optimistic that your review of the revised draft standards will make the vastly improved framework easier to discern.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	
Document Name	
Comment	
More clarification is needed related to the identification of Facility Ratings. As the Transmission Owners are already obligated to provide planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation). The drafting team should clarify that asset owners typically provide multiple ratings for a given asset based on various conditions and the intent of this standard is to ensure how the RC and PC pick those ratings is consistent.	
Likes 0	

Dislikes 0	
Response	
The rationale for Requirement R1 states, "The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." In order to ensure the requirement is adequately clear, the SDT is editing the requirement to include the descriptor "owner-provided" to the reference for Facility Ratings. Further, once Facility Ratings are provided by the applicable owner, it is then the responsibility of the RC to determine which of the ratings are to be used in operations and the responsibility of PC and/or TP to determine what ratings are appropriate for long-term planning.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	
Document Name	
Comment	
It appears that one of the objectives here is for the Planning Coordinator to make the Reliability Coordinator aware of system issues identified in the Planning Assessments that could impact the Operations timeframe. CHPD recommends that the TPL-001-4 standard, R8, be modified to add the Reliability Coordinator to the distribution of the Planning Assessment by the Planning Coordinator and Transmission Planner to adjacent Planning Coordinators and Transmission Planners. TPL-001-4 R8 allows the Reliability Coordinator to request this document already, but it would make sense to add the Reliability Coordinator (and possibly Transmission Operator) to the mandatory Planning Assessment distribution in order to pass on the issues observed in the assessment of planned operations for the planning horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under.	
David Jendras - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	

It seems to us that proposed standard FAC-015 is missing a requirement (R7) for the Transmission Planners to communicate any instability, Cascading, or uncontrolled separation in either its Planning Assessment information to its TOP, PC, and RC (similar to R6). This requirement would be a slight expansion of IRO-017-1 R3 and consideration should be given to moving this requirement to the new FAC-015-1 standard to keep all TP applicable items together.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees that some of the requirements would be better placed in other standards. However, modifying IRO-017-1 is out of the scope of the SAR that the SDT is working under.

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	
Comment	

Even though ReliabilityFirst agrees with the changes in the standard, ReliabilityFirst provides the following comments for consideration related to the Violation Severity Levels sections:

Violation Severity Levels

Requirement R4 VSL

The second part of the High and Severe VSL is confusing as it references "information" while Requirement R4 references "criteria". ReliabilityFirst recommends the following for consideration:

The Planning Coordinator failed to provide one element of the required criteria (i.e., Facility Ratings, System steady-state voltage limits, or stability performance criteria) to its Transmission Planners and to requesting Planning Coordinator's. The language of the first part of the High and Severe VSL are completely the same. Since there is no reference in any of the VLSs related to providing criteria to the requesting Planning Coordinators, ReliabilityFirst believes the first part of the Severe VSL should state "… to its requesting Planning Coordinators" instead of "… to all of its Transmission Planners."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made modifications to the VSLs.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - Sing Tay On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5; - Sing Tay	
Answer	
Document Name	
Comment	
Refer to comments submitted by SPP Standards Review Group.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Scott Downey - Peak Reliability - 1	
Answer	
Document Name	
Comment	
Peak believes that the Transmission Planner should be included along with the Planning Coordinator for communicating any instability, Cascading, or uncontrolled separation in FAC-015-1 requirement R6. Both Planning Coordinators and Transmission Planners perform Planning	

Assessments for the Near-Term Transmission Planning Horizon, therefore, it is possible that either entity could identify instability, Cascading, or uncontrolled separation in their Planning Assessments. The revised language could read, "Each Planning Coordinator and Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. Transmission Planners are not required to perform Transfer Capability Assessments, so any revised language might need to account for that.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the requirement to address your concern.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	
Document Name	
Comment	

The stated purpose of FAC-015-1 is:

"To ensure the Facility Ratings, System steady-state voltage limits, and stability [performance] criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology."

LSPT does not disagree with this purpose. It requires two-way communications between the RC and its TOPs and the PC and its TPs. However, LSPT proposes a more efficient way to meet this purpose.

Alternate FAC-015-000 Proposal

There are 15 Reliability Coordinators (per the NERC Compliance Registry) in the NERC footprint and they are listed below. Except for VACAR South and Peak Reliability, the rest are also registered as Planning Coordinators. In total, NERC has 78 Planning Coordinators are registered.

Reliability Coordinators in NERC (as of 9/29/2017)

1. Midcontinent Independent System Operator, Inc.
2. Saskatchewan Power Corporation
3. Southwest Power Pool
4. Hydro-Quebec TransEnergie
5. ISO-NE
6. New Brunswick Power Corporation
7. New York Independent System Operator
8. Ontario IESO
9. PJM Interconnection, LLC
10. Florida Reliability Coordinating Council, Inc.
11. Southern Company Services, Inc. - Trans
12. Tennessee Valley Authority
13. VACAR South
14. Electric Reliability Council of Texas, Inc.
15. Peak Reliability

As an alternative to the present FAC-015-1, LSPT suggests requiring each Reliability Coordinator to facilitate collaborative discussions with its Transmission Operators that use its SOL Methodology and with the Planning Coordinators and Transmission Planners in its Reliability Coordinator Area. Those discussions would be bounded by stated purpose of the proposed FAC-015-1 standard. The results of such discussions would be documented to identify any reliability-related gaps between operations and planning and vice versa regarding the purpose of the standard. For any identified gaps, the RC would be required to develop and implement a Corrective Action Plan. Progress on CAPs would be required to be collectively reviewed periodically (LSPT suggests this be no more than annually).

This is a far more efficient approach to address the standard's purpose.

Comments on FAC-015-1 as proposed

LSPT is pleased that the retirement of FAC-010-3 eliminated the unnecessary requirement for PCs to develop an SOL Methodology and use that methodology to develop SOLs and IROLs for the planning horizon. Although FAC-015-1 carried over language from the proposed retired FAC-010-3 and proposed revised FAC-014-2, LSPT does not agree with the requirements that FAC-015-1 would impose upon PCs and their associated TPs.

Per R1 through R5 in FAC-015-1, the Planning Assessment in R6 must either use the Facility Ratings, System steady-state voltage limits, and stability performance criteria from the RC's SOL Methodology *or* provide a technical justification to the RC if the PC's values differ from the RC's values. The RC is not subject to the standard, and as written, no method is proposed to resolve technical differences between the RC and PC.

There are many good reasons for differences between a Planning Assessment and an Operational Planning Assessment. For example, some RC's use a defined set of Normal and Emergency Facility Ratings based upon various ambient temperatures, including daytime and nighttime rating reflecting solar impacts. These ratings cover conditions that will be experienced by operators. Planner's typically use some of the RC's ratings as its 'seasonal ratings' that, when combined with the temperature impacts of load, stress the System. Each is correct in its application.

The end product in R6 is a Planning Assessment in the Near-Term Planning Horizon along with Corrective Action Plans for any deficiencies. This is well beyond FAC-015-1's stated purpose. In addition, it is largely duplicative or in TPL-001-4 requirements (see R2.7 in TPL-001-4), except that the implementation of TPL-001-4 would use planning and not operating assumptions.

The R6 phrase "or its Transfer Capability assessment" would not be produced in TPL-001-4. The SDT did not provide any rationale for this language.

FAC-015-1 does not state whether the PC and TP are required to use the SOL Methodology's Contingency List or its planning Contingency list per TPL-001-4.

In summary, FAC-015-1 places significant requirements on PCs and their TPs, and these requirements are not required to meet the standard's purpose. The main rationale for the FAC-015-1 requirements appears to be that they came from standards being retired (FAC-010-3) or revised (FAC-014-2). The SDT should justify the requirements on their own merits independent of previous standards.

Likes 0	
Dislikes 0	

Response

The suggestion for the "Reliability Coordinator to facilitate collaborative discussions with its Transmission Operators that use its SOL Methodology and with the Planning Coordinators and Transmission Planners in its Reliability Coordinator Area" would be difficult to measure compliance with and would not necessarily produce a binding result.

Also, the language in the standard and rationale make clear that the existing Planning Assessment (TPL-001) and Transfer Capability assessment (FAC-013) are the applicable planning products to which FAC-015 refers. Since these assessments are already being performed by planning entities, the SDT feels that additional work required by FAC-015 should be minimal.

The SDT believes the updates to FAC-015-1 and the supporting documentation address the concerns documented by LS Power.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

R4 – would prefer to see something about requesting Planning Coordinators with a reliability need instead of any Planning Coordinator that requests.

R6 – could consider including what is provided to impacted RCs in the IRO-017 or TPL-001 standard. This seems to have requirements for the Planning Assessment scattered over 3 standards.

R6 – would have preferred use of the term "IROL like conditions" instead of words copied from the IROL definition.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed the requirement R4 which the SDT believes will address your concern. The SDT did evaluate IRO-017 and TPL-001 information provided by the PC, but felt that the additional specificity identified in proposed FAC-015-1 R4 (previously R6) will ensure the RC is provided exactly what is needed to perform its stability studies and any subsequent IROL identification rather than potentially an entire Planning Assessment where those details may or may not be included otherwise. The SDT has chosen to utilize the "instability, Cascading, and uncontrolled separation" terminology consistent throughout multiple standards as these conditions in addition to criteria identified in the SOL methodology for determining IROLs would constitute "IROL like" rather than inferring that "any" instability (e.g. single small unit angular instability) would constitute and warrant an IROL designation of its stability SOL.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	
One area of coordination that is missing is having the PC review stability limits or IROLs determined by the Transmission Operator and/or Reliability Coordinator, especially in cases where the limit was not determined by the PC – possibly because the PC only considered firm uses as per TPL-001-4 R1.1.5 or Transfer Capability assessment methodology (FAC-013-2 R1) did not stress the same area as the operating assessments. The PC may want to consider the identified stability limit for future confirmation in a Planning Assessment or Transfer Capability Assessment. The criteria for the selection of transfers to be assessed (FAC-013-2 R1.1) could be based on review of information provided to the PC from the RC/Transmission Operator. It is preferable to modify FAC-013-2 to address this issue rather than include in FAC-015.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has proposed FAC-014-3 R5 as the mechanism for which the RC and TOP would communicate any stability limits or IROLs determined by the Transmission Operator and/or Reliability Coordinator. This maintains the task in a standard that the RC and TOP is familiar with and is appropriate for communication of SOLs with other entities rather than including in FAC-013.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	
Document Name	
Comment	
Note: While we agree with the retirement of FAC-010, and revisions to FAC-011 and 014 we will be voting "No" because of our concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We appreciate that you agree with the SDT's rationale for the retirement of FAC-010-3, the need for substantial revisions to FAC-011-4 and FAC-014-3, and the need for the proposed new FAC-015-1 standard. In response to your and other comments, the SDT has made substantial modifications to FAC-015-1 to address the stated concerns. We are optimistic that your review of the revised draft standards will make the vastly improved framework easier to discern.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The NSRF remains concerned with the proposed definition of "System Voltage Limit" as the phrase "reliable system operations" was replaced with "acceptable System performance." Acceptable System performance should rely on, among other factors, the definition of SOL	

Exceedance which is in a separate ballot and ballot period. It is inappropriate to approve a NERC standard without a clear understanding of how the definitions will impact the standard. The NSRF remains concerned with unintended impacts of separating the standard and the proposed SOL definition. The NSRF also has this concern with the following question.

Likes 1	Tay Sing On Behalf of: John Rhea, OGE Energy - Oklahoma Gas and Electric Co., 3, 1, 6, 5;
Dislikes 0	

Response

Thank you for your comment. The SDT has not modified the definition of "System Voltage Limit" as this definition was approved by industry and no comments were received that provided a clear need for modifying it. The SDT did however include acceptable system performance concepts that were included in the previously proposed SOL exceedance definition within proposed FAC-011-4 R6 to provide a clear understanding. The SDT has also proposed a new definition for SOL as well.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Thank you for the opportunity to comment on this new standard. However, BPA does not see the need to create new planning standards to accomplish the goals. Most of the requirements are either partially or fully included in other planning standards. The objectives could be better accomplished by adding or modifying existing planning standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Majority of commenters agree with the SDT's assessment that the proposed new FAC-015-1 standard is needed to enhance the "Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology" compared to the existing FAC-010, FAC-011 and FAC-014 standards plus the existing TPL-001-4 standard. We are optimistic that your review of the revised draft standards will make the vastly improved framework easier to discern.

The SDT agrees that some of the requirements in FAC-015-1 would be better placed in TPL-001. However, modifying TPL-001 is out of the scope of the SAR that the SDT is working under.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
Note: While we agree with the retirement of FAC-010, and revisions to FAC-011 and 014 we are voting "No" because of our concerns with FAC-015. These changes to FAC-010, FAC-011, FAC-014 and FAC-015 form an integrated whole, so approving the changes to some standards and not others could create a reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We appreciate that you agree with the SDT's rationale for the retirement of FAC-010-3, the need for substantial revisions to FAC-011-4 and FAC-014-3, and the need for the proposed new FAC-015-1 standard. In response to your and other comments, the SDT has made substantial modifications to FAC-015-1 to address the stated concerns. We are optimistic that your review of the revised draft standards will make the vastly improved framework easier to discern.	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
In regards to the proposed R5 (for which no questions have been asked by the SDT), why was "System steady-state voltage limits" used within this obligation rather than the newly proposed "System Voltage Limit?"	
Likes 0	
Dislikes 0	
Response	
Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

17. Do you agree with the proposed definition of System Voltage Limit? If not, please explain and provide alternative language.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Within the definition itself, is the word "limits" the best choice for supposedly indicating that it is a numerical value? Instead, might this be more appropriate? "*The maximum and minimum steady-state *voltage* ~~limits~~ (both normal and emergency) that provide for acceptable System performance.*"	
Likes 0	
Dislikes 0	
Response The SDT leveraged the word "limit" as "a prescribed maximum or minimum amount". Depending on the entity's systems and processes, System Voltage Limits can be defined in a variety of ways, such as per unit, percent of nominal, or voltage level.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends including separate definitions for minimum steady-state voltages and maximum steady-state voltages. Minimum steady-state voltage limits ensure acceptable power system performance while maximum steady-state voltage limits ensure equipment ratings are	

not exceeded. The approaches for determining and responding to exceedances are different for each type of voltage limit (minimum and maximum).

BPA therefore proposes the following revisions to the definition of System Voltage Limit:

"The minimum steady-state voltages (both pre-Contingency and post-Contingency) that provide for acceptable System performance. The maximum steady-state voltages based on equipment ratings (both Normal Rating and Emergency Rating) that provide for acceptable System performance."

Likes 0	
Dislikes 0	

Response

The SDT has found that there are situations that require System limits to voltage that are potentially more restrictive to voltage than that of any given Facility rating. As such, the definition is intended to encompass the entirety of limits to voltage that provide for acceptable System performance. Within the body of standards, it is the SDT's intent that requirements to System Voltage Limits dictate that they do not go beyond equipment-driven Facility Ratings.

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

As currently written, the words maximum and minimum introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, LES recommends the following change:

The steady-state voltage limits, **including both normal and emergency with applicable allowable timeframes**, that provide for acceptable System performance.

Likes 0	

Dislikes 0	
Response The SDT leveraged the word "limit" as "a prescribed maximum or minimum amount". Depending on the entity's systems and processes, System Voltage Limits can be defined in a variety of ways, such as per unit, percent of nominal, or voltage level. The proposed definition of SVL does not prohibit the application of time values with respect to SVL.	
Cynthia Kneisl - Midwest Reliability Organization - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
As currently written, the words *maximum* and *minimum* introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, the NSRF recommends the following change: The steady-state voltage limits**, including both normal and emergency with applicable allowable timeframes,** that provide for acceptable System performance.	
Likes 0	
Dislikes 0	
Response The SDT leveraged the word "limit" as "a prescribed maximum or minimum amount". Depending on the entity's systems and processes, System Voltage Limits can be defined in a variety of ways, such as per unit, percent of nominal, or voltage level. The proposed definition of SVL does not prohibit the application of time values with respect to SVL.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment	
CenterPoint Energy generally agrees with the proposed definition; however, we believe that the phrase, "acceptable System performance" could be subjective. System Voltage Limits should always respect, both in normal and emergency conditions, SOLs and IROLs, both of which are defined and measurable. CenterPoint suggests the following definition of System Voltage Limit for the SDT to consider: "The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for Reliable Operation of the BES." As a point of reference, the NERC glossary defines Reliable Operation as: "Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."	
Likes 0	
Dislikes 0	
Response The SDT felt that the use of the Reliable Operation term was extensive and specific enough that it might expand the definition of System Voltage Limit to include Facility Rating based voltage limits. System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. Incorporation of the Reliable Operation term could lead to entities having to report System-based and equipment-based as System Voltage Limits, which was not the intent of the definition or its intended use within the proposed standards.	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

Typically there are additional Thermal ratings above the "normal" limit that have a time frame associated with them. For example an emergency limit may be a 15 minute rating, i.e. the flow can be at the emergency rating for 15 minutes. Therefore, by design, being above the normal rating is not going to result in damage to the BES elements. Therefore the 1st bullet in the SOL Exceedance definition should be revised to "Actual flow through a Facility is above the Facility's Rating and the associated allowable time frame is exceeded.	
Likes 0	
Dislikes 0	
Response Thank you for your comments, however these particular comments do not seem applicable to the question around the System Voltage Limit definition.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
The existing constructs (Facility Ratings, voltage performance criteria, voltage stability/reactive margin) should be adequate to address high voltage conditions (typically through Facility Ratings) and low voltage (typically through voltage performance criteria and voltage stability/reactive margin). CHPD feels that introducing another voltage-limit term will only serve to confuse the meanings of these other terms. Additionally, CHPD feels it would have a greater reliability for NERC to develop a system voltage whitepaper to discuss various voltage Facility Ratings methods and the reliability concerns that should be addressed with low and high voltage performance criteria, as well as revisiting transient and reactive margin concepts. A whitepaper would help clarify expectations, bring useful dialogue and improve industry knowledge in this area, whereas a third defined term describing voltage will not likely bring the desired clarity. CHPD does not recommend the creation of the term 'System Voltage Limit'.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The suggestion for the inclusion of a term to distinguish voltage limits applicable to overall System performance from that of limits solely based off equipment/facility based was met with industry agreement within this SDT and the associated PRT.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees with other commenters that suggest the word “limits” should be removed from the System Voltage *Limit* definition

Likes 0	
Dislikes 0	

Response

The SDT leveraged the word “limit” as “a prescribed maximum or minimum amount”. Depending on the entity’s systems and processes, System Voltage Limits can be defined in a variety of ways, such as per unit, percent of nominal, or voltage level.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment	
As currently written, the words maximum and minimum introduce confusion as they seem to imply only one upper limit and one lower limit required by the definition. To improve clarity, ITC recommends the following change: The steady-state voltage limits, including both normal and emergency with applicable allowable timeframes, that provide for acceptable System performance.	
Likes 0	
Dislikes 0	
Response The SDT leveraged the word "limit" as "a prescribed maximum or minimum amount". Depending on the entity's systems and processes, System Voltage Limits can be defined in a variety of ways, such as per unit, percent of nominal, or voltage level. The proposed definition of SVL does not prohibit the application of time values with respect to SVL.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Concerns with the unapproved SOL and SOL Exceedance definitions and their applicability to this definition.	
Likes 0	
Dislikes 0	
Response Thank you for your comments, which will be incorporated into the 2015-09 SOL Project future work.	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR proposes removal of the phrase "(both normal and emergency)". In the rational the SDT stated they wanted to allow flexibility but including normal and emergency requires the establishment of multiple limits without guidelines of what the limits will address, i.e. finite time period, type of outage.	
Likes 0	
Dislikes 0	
Response The SDT is attempting to align the definition for System Voltage Limits with the concepts for normal and emergency limits as identified within the SOL Whitepaper.	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
To provide additional clarity and consistency with the proposed NERC Glossary Term, *System Operating Limit*, we recommend the proposed *System Voltage Limit* (SVL) definition affirmatively state SVLs are used in the operation of the BES. **Proposed alternative language**:	

"The maximum and minimum steady-state Facility voltage limits (both normal and emergency) used in the operation of the Bulk Electric System."	
Likes 0	
Dislikes 0	
Response The acceptable System performance referenced in the proposed definition is intended to convey that the System is expected to perform acceptably from a voltage perspective. The NERC defined term System is "A combination of generation, transmission, and distribution components." This term was used in the proposed definition to convey the idea that the System Voltage Limits established by the TOP in accordance with the RC's SOL Methodology are expected to be established in a manner that renders acceptable voltage performance for the System (as defined in the NERC glossary) that resides within the TOP Area. System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. (i.e., A voltage profile of 0.6 p.u. may not damage equipment, it is unacceptable from a System performance perspective.)	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
ATC does not believe there is a need for the term System Voltage Limit. The current FAC-008-3 standard already requires GOs and TOs to determine Facility voltage Ratings, and these ratings are already captured by the current SOL definition. Therefore, there is no need for the proposed definition of System Voltage Limit.	
Likes 0	
Dislikes 0	
Response The acceptable System performance referenced in the proposed definition is intended to convey that the System is expected to perform	

acceptably from a voltage perspective. The NERC defined term System is "A combination of generation, transmission, and distribution components." This term was used in the proposed definition to convey the idea that the System Voltage Limits established by the TOP in accordance with the RC's SOL Methodology are expected to be established in a manner that renders acceptable voltage performance for the System (as defined in the NERC glossary) that resides within the TOP Area. System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. (i.e., A voltage profile of 0.6 p.u. may not damage equipment, it is unacceptable from a System performance perspective.)

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
However, this proposal seems to be redundant with the FAC-008 voltage limit already established.	
Likes 0	
Dislikes 0	
Response The acceptable System performance referenced in the proposed definition is intended to convey that the System is expected to perform acceptably from a voltage perspective. The NERC defined term System is "A combination of generation, transmission, and distribution components." This term was used in the proposed definition to convey the idea that the System Voltage Limits established by the TOP in accordance with the RC's SOL Methodology are expected to be established in a manner that renders acceptable voltage performance for the System (as defined in the NERC glossary) that resides within the TOP Area. System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. (i.e., A voltage profile of 0.6 p.u. may not damage equipment, it is unacceptable from a System performance perspective.)	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
SRP generally supports the proposed definition. However SRP will be voting Negative on the ballot due to recommended changes to the proposed standards.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak agrees with the proposed definition for System Voltage Limit.	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
As a result of this change, does the definition of Facility Rating also need to change to remove "the maximum or minimum voltage" part of that definition?	
Likes 0	
Dislikes 0	
Response System Voltage Limits, by providing acceptable System performance, are intended to go beyond that of voltage limits based solely off facility/equipment limitations. (i.e., A voltage profile of 0.6 p.u. may not damage equipment, it is unacceptable from a System performance perspective.)	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Julie Hall - Entergy - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	
The SDT should consider a reference to facility voltage rating. The clarification should be provided that illustrates the relationship similar to between thermal facility rating and System Operation Limit; and facility voltage rating and System Voltage Limit.	
Likes 0	
Dislikes 0	
Response The SDT intends for the use of the System Voltage Limits term to be further clarified within the body of standards and the Reliability Coordinator's SOL Methodology.	

18. Do you agree with the Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
This is a significant paradigm shift for industry, affecting personnel from both operations and planning on how SOLs are handled and used within assessments. Time is needed to coordinate activities, particularly between RCs and PCs on how information is dispersed to TOPs and TPs, respectively. Additional time will also be needed for training that will include a larger audience than just operating personnel identified for Reliability Standard PER-005-2. Moreover, depending on the significance of a compliance burden introduced by these standards, registered entities will need time to procure additional staff and resources for their established compliance programs. We believe an implementation period no less than 24 months is appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

PNMR believes that the implementation time frame should be a minimum of 36 months to allow active participation by all impacted entities especially PA and TOPs since as written, FAC-011 and FAC-015 will require the PA and TOP to plan and operate their system to new system performance criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The 12 month implementation plan is only sufficient to put in place the required processes necessary to facilitate the requirements as stated in the new and revised standards. In order to then allow for a cycle of the TPL-001 standard to also be accommodated to facilitate this new SOL process another 12 months would need to be added into the implementation plan to allow for this work specifically.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	

Answer	No
Document Name	
Comment	
The new term and new/revised standards require Responsible Entities to develop a methodology and to establish further coordination between the RCs and TOPs. These efforts require more than 12 months for adequate development time and coordination between Responsible Entities. AECI recommends that the implementation plan should be extended to 24 months to allow Responsible Entities the time needed to implement the new/revised standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Standards need additional modification – once this is done, the proposed Implementation Plan can be assessed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Based on the level of work that is anticipated, Duke Energy does not agree with the proposed Implementation Plan, and recommends that the drafting team consider extending the Implementation Plan to 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
The new term System Voltage Limit and requirements in FAC-011-4 R3 will require methodology development and coordination between the RC and TOPs to address common limits as well as coordination. Once complete, the studies will need to be performed based on these new concepts, which may take more than 12 months. Also, the language in FAC-011-4 R2 is a change which will result in the need to address common limits as well as coordination.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT believes that establishing communication paths would not be burdensome since the standard is simply codifying practices that are already in existence. In addition, the majority of industry supported the proposed 12 month implementation period.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light would like to see the standard resolution first.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As documented above, BPA does not believe a new standard needs to be created.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	

Comment	
Peak agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP generally supports the proposed Implementation Plan. However SRP will be voting Negative on the ballot due to recommended changes to the proposed standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Michael Jones - National Grid USA - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 3	PSEG - PSEG Energy Resources and Trade LLC, 6, Barton Karla; PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

19. The SDT asserts the combination of proposed FAC-011-4, FAC-014-3, and FAC-015-1 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As documented above, BPA does not believe a new standard needs to be created.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation has concerns with possible misinterpretation of FAC-011-4 R4.2 and R5 as it implies Real-Time Assessments will include Stability. Reclamation also does not agree with the identified single Contingency and multiple Contingencies for use in determining stability limits because the TOP will inform the RC which Contingencies are credible.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
As proposed, we perceive this Standard as requiring additional resources for stability studies and compliance documentation such that it will add cost to our business. Furthermore, the proposed Standard will not change the way we increase reliability or operate the system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Changes proposed to FAC-011-4 and FAC-014-3 as well as the retirement of FAC-010-3 are reasonable. The development of FAC-015 seems to be burdensome, especially the Facility Rating comparison exercise. Some of the proposed changes fit better into existing standards TPL-001 and FAC-013.	
Likes 1	Michael Watkins, N/A, Watkins Michael
Dislikes 0	

Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
LSPT's proposed alternative to FAC-015-1 in Q16 meets the proposed standard's purpose in a more efficient manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Only consistency in requirements and criteria would help to increase "cost effectiveness" in our environment where legal/regulatory approval processes impede the effort in maintaining system reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The method that the set of standards has been put together forces everyone into a defined process rather than defining the objective of the standard and allowing every group to identify their own cost effective method of accomplishing the objective. The organization of the requirements especially with those found in FAC-015 should have been incorporated in other already existing standards (TPL-001 or IRO-017). This new proposed standard is not cost effective and sets up organizations for compliance risks due to developing a third standard with obligations tied to the TPL-001 standard that should have just been added to this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We do not see any flexibility to meet the objectives. For standard FAC-015-1, we have offered alternative ideas that the PC and RC should be providing technical justification for developing more stringent system performance requirements than the system is presently planned. We believe that if the draft language remains unchanged, depending on the imposed requirement by the PC or RC, significant dollars may need to be expended to meet the new, more stringent requirements.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNMR believes that the proposed FAC-011 and FAC-015 allow one entity, the RC, to change long standing system performance criteria used by entities for the operation and planning of the system which could result in the need to implement numerous system changes to meet the RC's criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
ATC is concerned with the application of the RC SOL methodology to the TOP through FAC-014-3 with respect to the requirements regarding stability limits and stability analysis in FAC-011-4 R4 and R5. The current proposal may require a significant increase in stability analyses, whether in OPAs and RTAs, that are not warranted in a local TOPs system but is mandated because a TOP must follow an RC's one-size-fits-all methodology.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The proposed standards require direct communication between the RC and the impacted entities that would be documented through electronic communications or voice recordings. This approach is cumbersome and inefficient. We believe the standards should instead allow entities to use more automated mechanisms for exchanging SOL information. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The SDT will forward your comments on to the appropriate NERC staff.	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting NPCC comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response and clarifying comment. The SDT will forward your comments on to the appropriate NERC staff.
Janis Weddle - Public Utility District No. 1 of Chelan County - 6, Group Name Chelan PUD

Answer	Yes
Document Name	
Comment	
Workload and operational impacts are likely to be in-line with current practice. While FAC-010 is proposed to be removed, FAC-015 replaces it, so the baseload compliance workload remains unchanged.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The SDT will forward your comments on to the appropriate NERC staff.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA believes the overall approach can be a cost effective manner to meet the reliability objectives, provided that the scope of activities for each involved functional entity is made abundantly clear so that unnecessary or duplicative work is not required. We believe additional changes, as suggested above, are needed to reach that point.	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The SDT will forward your comments on to the appropriate NERC staff.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison Electric Institute - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Powell - Trans Bay Cable LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Faz Kasraie	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Grimshaw - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	
Some of the proposed requirements, (for examples: Requirement R3, Parts 3.1 in FAC-011-4), could result in unnecessary cost for the responsible entities without any reliability benefits. We urge the SDT to consider adopting our proposed wording changes to achieve a more cost-effective approach to meeting the reliability objectives.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will forward your comments on to the appropriate NERC staff.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	Project 2015-09 Establish and Comm SOL.docx
Comment	

Likes 0	
Dislikes 0	
Response	

Standards Announcement

Reminder

Project 2015-09
Establish and Communicate System Operating Limits

Initial Ballots and Non-binding Polls Open through November 13, 2017

Now Available

Initial ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, November 13, 2017** for the following standards, implementation plan and proposed definition:

1. **FAC-011-4 –** System Operating Limits Methodology for the Operations Horizon;
2. **FAC-014-3 –** Establish and Communicate System Operating Limit;
3. **FAC-015-1 –** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology;
4. **Implementation Plan;** and
5. **Proposed definition of System Voltage Limit**.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience issues navigating the SBS, contact Nasheema Santos.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact either Senior Standards Developer, Darrel Richardson at (609) 613-1848 or Al McMeekin at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2015-09
Establish and Communicate System Operating Limits

Formal Comment Period Open through November 13, 2017
Ballot Pools Forming through October 30, 2017

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, November 13, 2017** for:

1. **FAC-010-3** – System Operating Limits Methodology for the Planning Horizon (retirement)
2. **FAC-011-4** – System Operating Limits Methodology for the Operations Horizon
3. **FAC-014-3** – Establish and Communicate System Operating Limit
4. **FAC-015-1** – Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
5. **Implementation Plan**
6. **Proposed definition of System Voltage Limit**

Commenting
Use the Standards Balloting & Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Monday, October 30, 2017.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Initial ballots for the standards, implementation plan, proposed definition and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 3-13, 2017**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

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Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-011-4 IN 1 ST
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 268
Total Ballot Pool: 308
Quorum: 87.01
Weighted Segment Value: 58.12

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	88	1	34	0.557	27	0.443	0	17	10
Segment: 2	8	0.7	2	0.2	5	0.5	0	1	0
Segment: 3	68	1	27	0.574	20	0.426	0	12	9
Segment: 4	15	0.9	5	0.5	4	0.4	0	2	4
Segment: 5	67	1	25	0.532	22	0.468	0	9	11
Segment: 6	50	1	17	0.472	19	0.528	0	9	5
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	308	6.6	120	3.836	97	2.764	0	51	40

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Third-Party Comments
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
					Comments

5	Salt River Project	Kevin Nielsen		Negative	Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Negative	Comments Submitted
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Negative	Third-Party Comments
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A

1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	None	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Negative	Comments Submitted
5	Seattle City Light	Mike Haynes	Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	Charles Freibert	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
4	Austin Energy	Esther Weekes	Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Negative	Comments Submitted
1	Eversource Energy	Quintin Lee	Affirmative	N/A

6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Aaron Austin		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
	Great Plains Energy - Kansas City Power and Light		Douglas		

3	Co.	John Carlson	Webb	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Third-Party Comments
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party

					Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
	Boise-Kuna Irrigation District - Lucky Peak Power				Third-Party

5	Plant Project	Mike Kukla		Negative	Comments
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Abstain	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Abstain	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Abstain	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments

6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Third-Party Comments
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
3	CPS Energy	James Grimshaw		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 IN 1 ST
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 272
Total Ballot Pool: 313
Quorum: 86.9
Weighted Segment Value: 63.17

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	43	0.642	24	0.358	0	11	12
Segment: 2	8	0.7	2	0.2	5	0.5	0	1	0
Segment: 3	70	1	37	0.661	19	0.339	0	5	9
Segment: 4	15	1	6	0.6	4	0.4	0	1	4
Segment: 5	68	1	29	0.569	22	0.431	0	7	10
Segment: 6	50	1	23	0.561	18	0.439	0	4	5
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	313	6.7	150	4.232	92	2.468	0	30	41

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A

4	Seattle City Light	Hao Li		Negative	Third-Party Comments
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Negative	Comments Submitted
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A

6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Negative	Third-Party Comments
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted

10	Texas Reliability Entity, Inc.	Rachel Coyne	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	None	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Negative	Comments Submitted
5	Seattle City Light	Mike Haynes	Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette	Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
4	Austin Energy	Esther Weekes	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Negative	Comments Submitted
1	Eversource Energy	Quintin Lee	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Abstain	N/A
3	Black Hills Corporation	Don Stahl	None	N/A
5	Portland General Electric Co.	Ryan Olson	None	N/A

3	AEP	Aaron Austin		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted

3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Third-Party Comments
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A

1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A

1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments

1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A

1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
3	CPS Energy	James Grimshaw		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-015-1 IN 1 ST
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 272
Total Ballot Pool: 313
Quorum: 86.9
Weighted Segment Value: 56.55

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	39	0.582	28	0.418	0	11	12
Segment: 2	8	0.7	1	0.1	6	0.6	0	1	0
Segment: 3	70	1	33	0.589	23	0.411	0	5	9
Segment: 4	15	1	5	0.5	5	0.5	0	1	4
Segment: 5	68	1	27	0.529	24	0.471	0	7	10
Segment: 6	50	1	20	0.488	21	0.512	0	4	5
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	313	6.7	135	3.789	107	2.911	0	30	41

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
					Comments

5	Salt River Project	Kevin Nielsen		Negative	Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Third-Party Comments
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments

					Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A

1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted

1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Aaron Austin		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted

3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Martine Blair		Negative	Comments Submitted
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Third-Party Comments
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted

3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons	Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker	Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw	Abstain	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	Santee Cooper	Shawn Abrams	Abstain	N/A
6	Santee Cooper	Michael Brown	Abstain	N/A
3	Santee Cooper	James Poston	Abstain	N/A
5	Santee Cooper	Tommy Curtis	Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe	Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
3	Platte River Power Authority	Jeff Landis	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle	Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell	Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris	Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas	None	N/A
1	Muscatine Power and Water	Andy Kurriger	Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff	Abstain	N/A

3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A

1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
3	CPS Energy	James Grimshaw		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Third-Party

				Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits Implementation Plan IN 1 OT
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 305
Quorum: 85.57
Weighted Segment Value: 76.4

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	48	0.774	14	0.226	0	13	14
Segment: 2	8	0.5	5	0.5	0	0	0	3	0
Segment: 3	69	1	42	0.792	11	0.208	0	7	9
Segment: 4	14	0.9	5	0.5	4	0.4	0	2	3
Segment: 5	66	1	31	0.689	14	0.311	0	10	11
Segment: 6	49	1	25	0.658	13	0.342	0	5	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	305	6.3	165	4.813	56	1.487	0	40	44

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
4	Seattle City Light	Hao Li		Negative	Third-Party Comments
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A

5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Aaron Austin		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
		Salvatore			

1	New York Power Authority	Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments

4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Abstain	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Abstain	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A

5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
					Comments

5	Bonneville Power Administration	Francis Halpin	Negative	Submitted
3	CPS Energy	James Grimshaw	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Affirmative	N/A
1	CPS Energy	Gladys DeLaO	Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt	Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits System Voltage Limit | New Definition IN 1 DEF
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: DEF
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 267
Total Ballot Pool: 311
Quorum: 85.85
Weighted Segment Value: 68.59

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	45	0.672	22	0.328	0	10	13
Segment: 2	8	0.7	3	0.3	4	0.4	0	1	0
Segment: 3	69	1	38	0.691	17	0.309	0	5	9
Segment: 4	14	1	7	0.7	3	0.3	0	0	4
Segment: 5	68	1	31	0.633	18	0.367	0	8	11
Segment: 6	51	1	24	0.6	16	0.4	0	5	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	311	6.7	158	4.595	80	2.105	0	29	44

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A

4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A

6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		None	N/A

6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
5	Seattle City Light	Mike Haynes	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette	Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
4	Austin Energy	Esther Weekes	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Negative	Comments Submitted
1	Eversource Energy	Quintin Lee	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Abstain	N/A
3	Black Hills Corporation	Don Stahl	None	N/A
5	Portland General Electric Co.	Ryan Olson	None	N/A
3	AEP	Aaron Austin	Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley	Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Affirmative	N/A
3	Duke Energy	Lee Schuster	Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale	Negative	Third-Party Comments
1	OTP - Otter Tail Power Company	Charles Wicklund	Negative	Third-Party Comments

1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments

5	Sempra - San Diego Gas and Electric	Jerome Gobby		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Third-Party Comments
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A

5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted

3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments

1	Seattle City Light	Pawel Krupa	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles	Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble	None	N/A
5	Cowlitz County PUD	Ron Sporseen	Affirmative	N/A
1	M and A Electric Power Cooperative	William Price	None	N/A
3	City of Farmington	Linda Jacobson-Quinn	None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea	None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty	None	N/A
5	Ontario Power Generation Inc.	David Ramkalawan	Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Francis Halpin	Negative	Comments Submitted
3	CPS Energy	James Grimshaw	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Affirmative	N/A
1	CPS Energy	Gladys DeLaO	Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt	Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

NERC Balloting Tool

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Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-011-4 Non-binding Poll IN 1 NB
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 243
Total Ballot Pool: 290
Quorum: 83.79
Weighted Segment Value: 56.97

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	26	0.605	17	0.395	26	13
Segment: 2	7	0.3	2	0.2	1	0.1	4	0
Segment: 3	67	1	22	0.579	16	0.421	19	10
Segment: 4	14	0.9	5	0.5	4	0.4	2	3
Segment: 5	63	1	19	0.543	16	0.457	13	15
Segment: 6	45	1	12	0.429	16	0.571	12	5
Segment: 7	1	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	1

Segment: 10	8	0.7	6	0.6	1	0.1	1	0
Totals:	290	6.1	94	3.655	71	2.445	78	47

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Abstain	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
					Comments

4	Seattle City Light	Hao Li		Negative	Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A

5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
5	Westar Energy	Derek Brown		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		None	N/A

5	Seattle City Light	Mike Haynes		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Esther Weekes		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Aaron Austin		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A

6	Entergy	Julie Hall		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted

1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted

1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A

6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Abstain	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Abstain	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A

6	Associated Electric Cooperative, Inc.	Brian Ackermann		Abstain	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
3	CPS Energy	James Grimshaw		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 Non-binding Poll IN 1 NB
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 294
Quorum: 84.01
Weighted Segment Value: 65.95

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	35	0.714	14	0.286	20	13
Segment: 2	7	0.3	2	0.2	1	0.1	4	0
Segment: 3	68	1	31	0.689	14	0.311	13	10
Segment: 4	14	1	6	0.6	4	0.4	1	3
Segment: 5	65	1	23	0.605	15	0.395	12	15
Segment: 6	46	1	17	0.548	14	0.452	10	5
Segment: 7	1	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	1

Segment: 10	8	0.7	6	0.6	1	0.1	1	0
Totals:	294	6.2	122	4.157	63	2.043	62	47

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A

5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
5	Westar Energy	Derek Brown		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Aaron Austin		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted

1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A

5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A

6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A

6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
3	CPS Energy	James Grimshaw		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-015-1 Non-binding Poll IN 1 NB
Voting Start Date: 11/3/2017 12:01:00 AM
Voting End Date: 11/14/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 294
Quorum: 83.67
Weighted Segment Value: 51.91

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	27	0.563	21	0.438	21	13
Segment: 2	7	0.3	1	0.1	2	0.2	4	0
Segment: 3	68	1	25	0.556	20	0.444	13	10
Segment: 4	14	1	5	0.5	5	0.5	1	3
Segment: 5	65	1	18	0.474	20	0.526	12	15
Segment: 6	46	1	12	0.387	19	0.613	10	5
Segment: 7	1	0	0	0	0	0	1	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0	0	0	0	0	0	1

Segment: 10	8	0.6	5	0.5	1	0.1	1	1
Totals:	294	6.1	95	3.279	88	2.821	63	48

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
					Comments

4	Seattle City Light	Hao Li		Negative	Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A

1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
5	Westar Energy	Derek Brown		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		None	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		None	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
6	Black Hills Corporation	Brooke		None	N/A

		Voorhees		
5	Seattle City Light	Mike Haynes	Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank	None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
4	Austin Energy	Esther Weekes	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Negative	Comments Submitted
1	Eversource Energy	Quintin Lee	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Abstain	N/A
3	Black Hills Corporation	Don Stahl	None	N/A
5	Portland General Electric Co.	Ryan Olson	None	N/A
3	AEP	Aaron Austin	Abstain	N/A
1	Long Island Power Authority	Robert Ganley	Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula	Abstain	N/A
3	Duke Energy	Lee Schuster	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake	Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund	None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams	Affirmative	N/A

5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Martine Blair		Negative	Comments Submitted

6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
					Comments

5	Omaha Public Power District	Mahmood Safi		Negative	Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Brandon Ware		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted

10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
6	Basin Electric Power Cooperative	Paul Huettl		Negative	Comments Submitted

4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Ron Sporseen		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		None	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A

5	DTE Energy - Detroit Edison Company	Adrian Raducea	None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty	None	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Francis Halpin	Negative	Comments Submitted
3	CPS Energy	James Grimshaw	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Affirmative	N/A
1	CPS Energy	Gladys DeLaO	Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt	Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limit, unless the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service relay settings for under voltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and provide the method for determining the common System Voltage Limits to be used in operations;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. unit stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL Methodology the Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study. The SOL Methodology shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-time Assessments.

5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.

5.4. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement R4, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator. The method shall address the periodicity for communicating established SOLs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

R9. Each Reliability Coordinator shall provide its SOL Methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months. .

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of

				Requirement R3 into its SOL Methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator failed to include Part 7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 7.1 and 7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part 7.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
R8.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.
R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
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4		Project 2015-09 – Adopt revisions to standard.	Revisions

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Reliability Coordinator
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ~~the applicable~~which owner-provided Facility Ratings are to be used in operations~~. The method shall address the use of common Facility Ratings between the Reliability Coordinator and~~ such that the Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus~~es~~/station~~s~~ have an associated System Voltage Limit, unless~~ except for~~ the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations ~~that may be excluded as specified in the Reliability Coordinator's SOL Methodology~~from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect ~~the~~voltage-based Facility~~ voltage~~ Ratings;

3.3. Require that System Voltage Limits are ~~higher~~greater than or equal to in-service relay settings for under voltage load shedding ~~(UVLS) relay settings~~systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. ~~Address~~Require ~~-~~the use of common System Voltage Limits between the ~~Reliability Coordinator and the~~ Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~ and provide the method for determining the common System Voltage Limits to be used in operations;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~angular~~unit stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how ~~instability risks~~stability limits are ~~identified~~determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages~~;~~.

4.5. Describe the level of detail that is required for the study model(s)~~;~~, including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. ~~;~~

~~**4.6.**~~**4.7.** State that the ~~planned~~ use of underfrequency load shedding (UFLS) ~~is~~programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall ~~include~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs~~).~~) for the area under study. The ~~method~~SOL Methodology shall ~~include~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. ~~The~~Specify the following ~~list of~~ single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with ~~normal clearing~~Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. ~~Any~~Identify any additional single or multiple Contingency events or types of ~~single~~ Contingency events ~~identified~~for use in performing Operational Planning Analysis and Real-time Assessments.

~~**5.2.**~~**5.3.** Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits~~, or for use in performing OPAs and RTAs.~~.

~~**5.3.** Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.~~

5.4. ~~The method for considering~~Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement ~~R6 to identify the Contingencies for~~R4, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

~~R6.~~R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~6.1.~~7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~6.2.~~7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

~~M6.~~M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs ~~it established~~ to the ~~its~~ Reliability Coordinator~~(s)~~. The method shall address the periodicity for communicating established~~of~~ SOLs~~ communication~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M7.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~R8.~~R9. Each Reliability Coordinator shall provide its SOL Methodology ~~and any changes to the SOL Methodology prior to the effective date of the SOL Methodology,~~ to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~8.1.~~9.1. Each~~Each adjacent Reliability Coordinator within an Interconnection, and each~~ Reliability Coordinator that requests and indicates it has a reliability-related need~~;~~ within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same~~an~~ Interconnection;

~~8.1.1.~~9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

~~8.1.2.~~9.2.3. Each Transmission Operator within its Reliability Coordinator Area~~.~~; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

~~M8.~~M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through ~~R8~~R9 for the current year plus the previous 12 calendar months. .

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of

				Requirement R3 into its SOL Methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
~~R6~~R7.	N/A	N/A	The Reliability Coordinator failed to include Part ~~6~~7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts ~~6~~7.1 and ~~6~~7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part ~~6~~7.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part ~~6~~7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
~~R7~~R8.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.
~~R8~~R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~one~~three of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~two~~four or more of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in ~~Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology.~~Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1.

D. Regional Variances

None.

E. Associated Documents

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Version History

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1	November 1, 2006	Adopted by Board ~~of Trustees~~	New
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Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability

Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, that demonstrates the Transmission Operator and Reliability Coordinator used the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the RC needs such information	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	N/A	A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
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~~45-day formal comment period with ballot~~	~~September 2017 – October 2017~~
45-day formal comment period with additional ballot	~~January~~August 2018 – ~~February~~October 2018
10-day final ballot	~~February~~October 2018
NERC Board ~~(Board)~~ adoption	~~May~~November 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Reliability Coordinator
   4.1.2. Transmission Operator
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability

Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the ~~derivation of the~~ stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate that~~, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator ~~that is impacted by an IROL~~ shall ~~provide Transmission Owners and Generation Owners within its~~ use the Bulk Electric System performance criteria specified in the Reliability ~~Coordinator Area a list of Facilities owned by that entity that are critical~~Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to ~~the derivation of the IROL.~~determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation~~ to demonstrate,~~ that demonstrates the Transmission Operator and Reliability Coordinator ~~provided~~used the ~~list of Facilities~~Bulk Electric System performance criteria specified in ~~accordance with Requirement R6~~the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention:
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through ~~R6~~R8 for the current year plus the previous 12 calendar months.

   1.3. Compliance Monitoring and Enforcement Program
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be

used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator ~~did not~~failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but ~~did not~~failed to provide its SOLs at the periodicity at which the RC needs such	The Transmission Operator ~~did not~~failed to provide its SOLs to its Reliability Coordinator.

			information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.
R5.	The Reliability Coordinator ~~did not~~failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.
R6.	N/A	N/A	N/A	~~The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.~~A Transmission Operator or

				Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board ~~of Trustees~~	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
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3		Project 2015-09 Adopt revised standard.	Revision

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
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45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
2. **Number:** FAC-015-1
3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning

Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

4.2 The associated stability criteria used as part of determining the instability;

4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;

4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;

4.5 Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R4 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

R3.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in Planning Assessments are equally limiting or more limiting than the stability performance criteria established in the Reliability Coordinator's SOL Methodology.
R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement R4, Parts 4.1 – 4.6. OR

				The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
2. **Number:** FAC-015-1
3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Planning Coordinator
     - **4.1.2.** Transmission Planner
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than ~~those established~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~ The process may allow the ~~Planning Coordinator uses~~use of less limiting Facility Ratings ~~than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-‑state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits ~~established~~used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria ~~established~~used in ~~its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

~~**R4.**~~ Each Planning Coordinator ~~shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to~~

~~its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M4.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.~~

~~**R5.** Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M5.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.~~

~~R6.~~R4. ~~Each Planning Coordinator~~and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator~~ and~~, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

~~6~~4.2 The associated stability criteria used as part of determining the instability;

~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation;

~~6.4~~4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;

4.5 Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

~~M6.~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement ~~R6~~R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through ~~R6~~R4 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	~~The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but ~~did not document the technical justification.~~failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	~~The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its

			technical ~~justification~~rationale.	Reliability Coordinator's SOL Methodology.
R3.	N/A	~~The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its technical ~~justification~~rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in ~~planning assessments~~Planning Assessments are equally limiting or more limiting than ~~those used in operations~~the stability performance criteria established in the Reliability Coordinator's SOL Methodology.
~~**R4.**~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide one element of the required information.~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide two or more elements of the required information.~~

~~R5.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.~~
~~R6~~R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator~~ and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator~~ and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator~~ and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator~~ and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6~~.5~~. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted

				Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits
- CIP-014-2 Physical Security
- FAC-003-4 Transmission Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements
- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
  - Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.
- Implementation of PRC-026-1
  - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- ~~Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")~~
  - FAC-011-4 System Operating Limits Methodology for the Operations Horizon
  - FAC-014-3 Establish and Communicate System Operating Limits
  - FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

~~[*New/Modified/Retired*] Terms in the NERC Glossary of Terms~~

~~Proposed New Definition(s):~~

~~System Voltage Limit: The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.~~

~~Applicable Entities~~

- ~~Reliability Coordinator~~
- ~~Planning Coordinator~~
- CIP-014-2 Physical Security
- FAC-003-4 Transmission ~~Planner~~Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission ~~Operator~~Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
    - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
    - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
    - Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.
- Implementation of PRC-026-1
    - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
    - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1 ~~and~~ , CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and ~~term~~terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1 ~~and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and ~~term~~terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, ~~and FAC-014-2~~FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and FAC-015.~~FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18 - 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Physical Security
2. **Number:** CIP-014-3
3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates: See Implementation Plan

6. Background:

Reliability Standard CIP-014-3 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or
- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	
3	TBD	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Section 4 Applicability

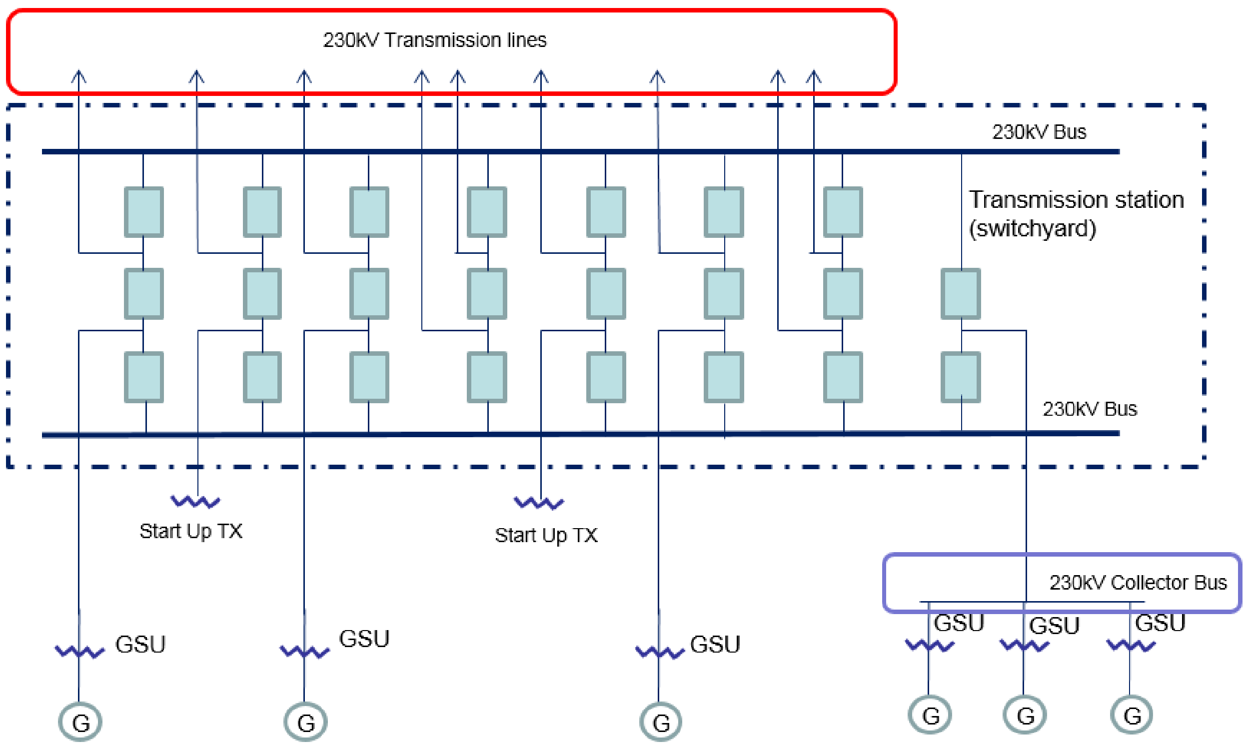
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security

(*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System for planning events. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase “Transmission stations or Transmission substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or

Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential

4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within

120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

  Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

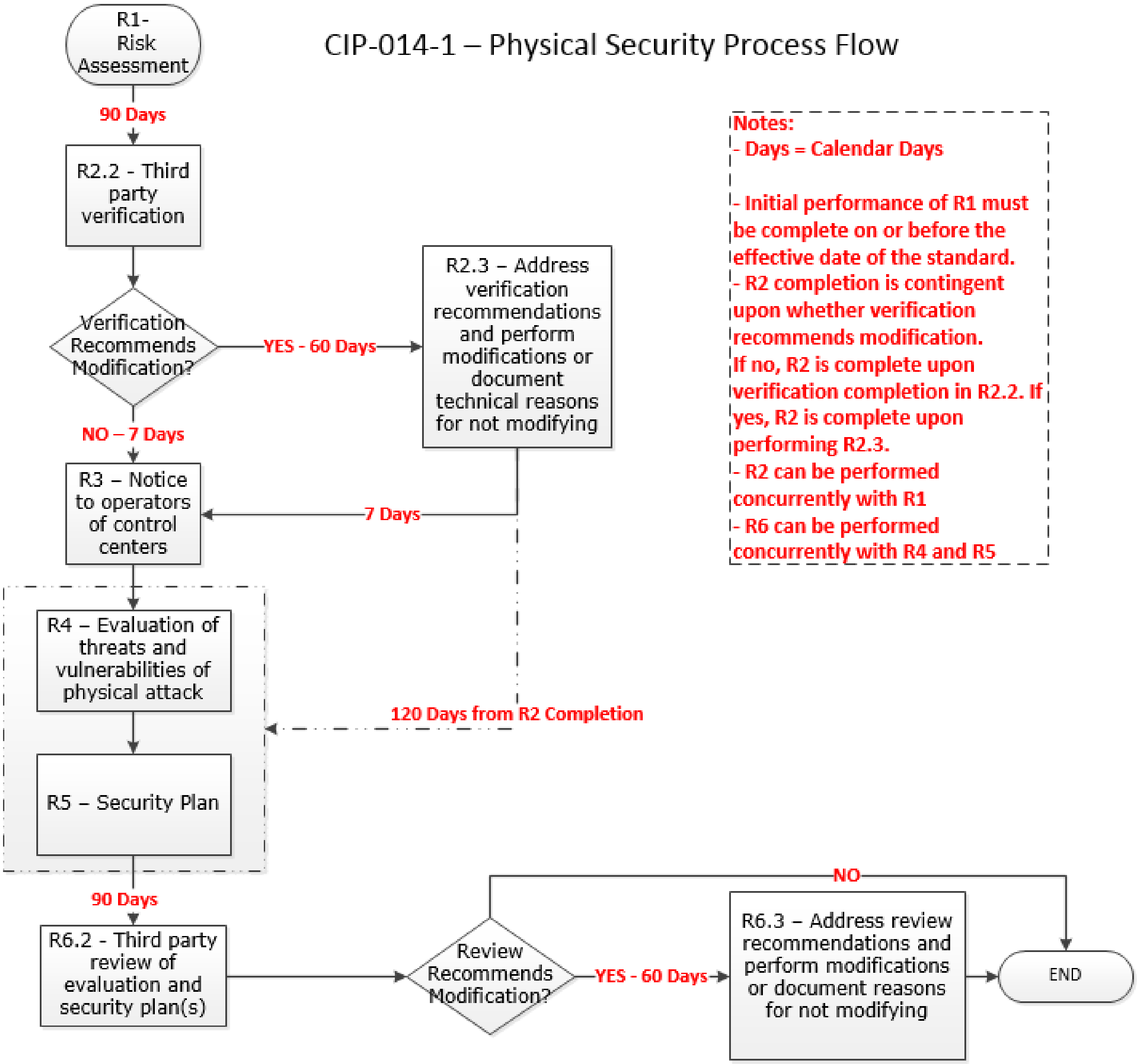
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
7 Days
R3 – Notice to operators of control centers
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
NO
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Physical Security
2. **Number:** CIP-014-3~~2~~
3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the ~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-3~~2~~.

6. Background:

~~This~~ Reliability Standard CIP-014-2 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner’s and Transmission Operator’s facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove "widespread".	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

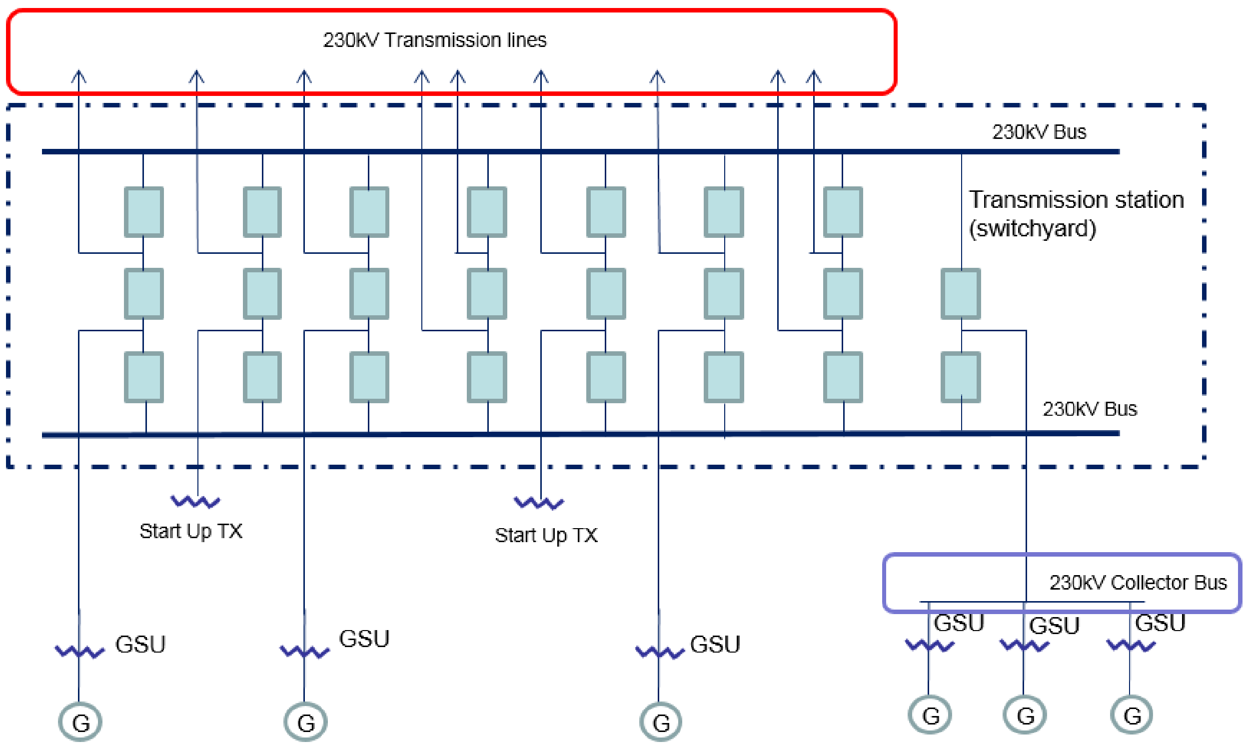
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in ~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~instability, uncontrolled separation, or Cascading. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that “only an instability that has a “critical impact on the operation of the interconnection” warrants finding that the facility causing the instability is critical under Requirement R1.” The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

<u>Performing Risk Assessments</u>

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

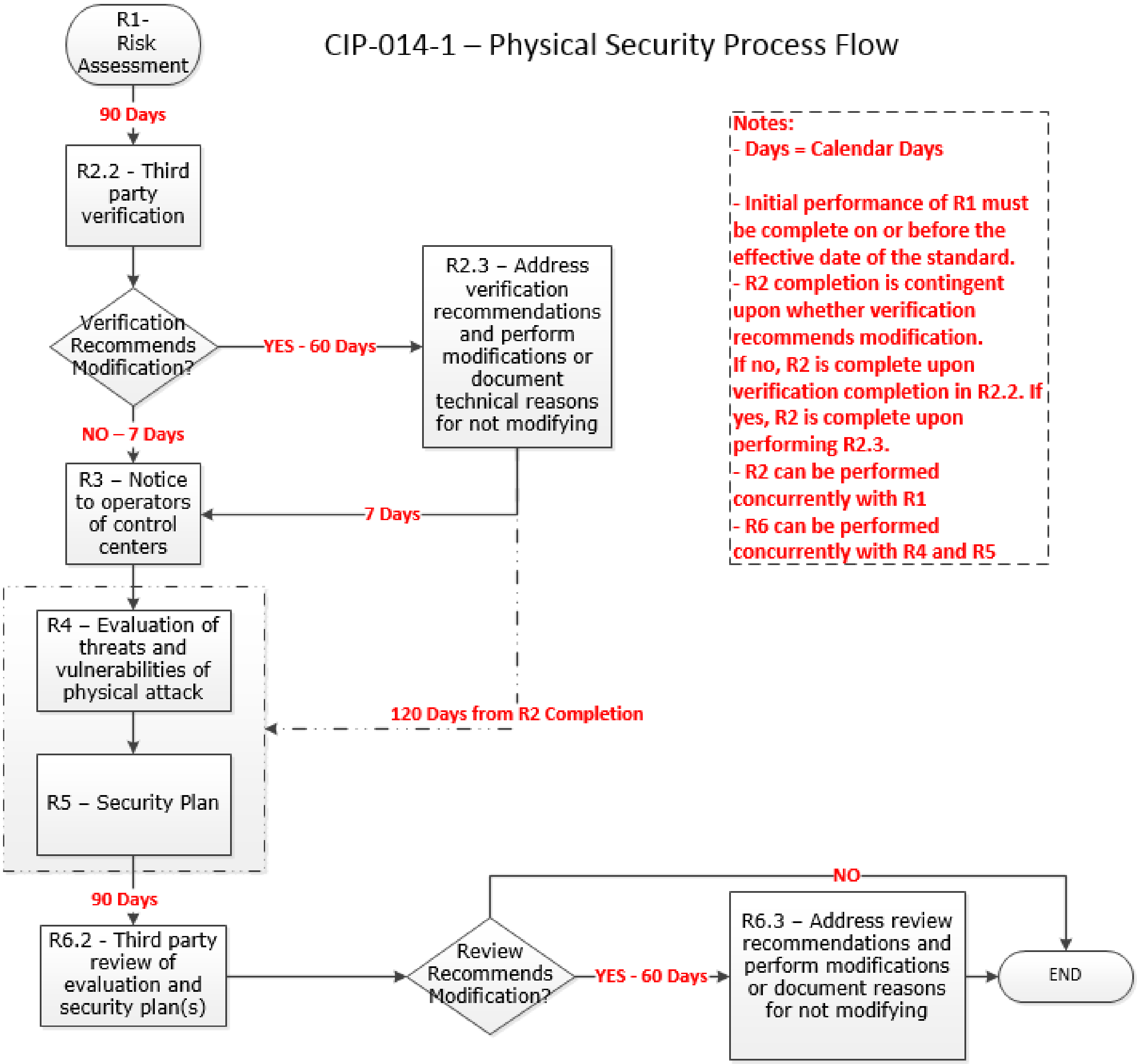
- *An entity or organization approved by the ERO.*

- *A governmental agency with physical security expertise.*

- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
NO
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system* <u>*performance result or outcome*</u>*?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that* <u>*reduces a stated risk*</u> *to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have* <u>*what capability*</u>*, to achieve what particular result or*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

2.1.

M2. [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this Reliability Standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

(as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:**
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
   - The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
   - If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

   1.3. **Compliance Monitoring and Enforcement Program**
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

   1.4. **Additional Compliance Information**

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;

- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, blowing together from within the ROW.

  The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and*

				vegetation located inside the active transmission line ROW • *A grow-in*
R2.				•
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action

				when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

		requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[15] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[16] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[17] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators may designate lines below 200 kV, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation is a greater risk to the interconnected electric transmission system than applicable lines that have not been identified as such. Applicable lines that have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line’s Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

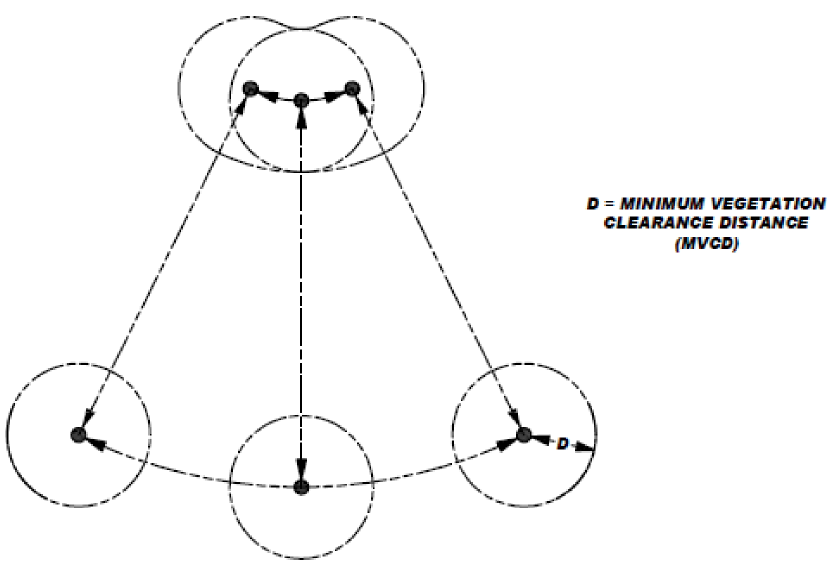

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained

Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain

reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**

765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-54
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

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[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for R~~r~~eliability S~~s~~tandards development recognizes that each requirement in a NERC R~~r~~eliability S~~s~~tandard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability S~~s~~tandards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a R~~r~~eliability S~~s~~tandard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s)~~, which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all

Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:~~

~~**2.1.** An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]~~

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

~~[9] See footnote 4.~~

~~[10] See footnote 5.~~

~~**2.2.** An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]~~

~~**2.3.** An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]~~

~~2.4.~~2.1. ~~An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

M2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)~~

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the

~~[11] See footnote 6.~~
~~[12] *Id.*~~
~~[13] *Id.*~~

associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW*

				• *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~*A fall-in from inside the active transmission line ROW*~~ • ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~ • ~~*A grow-in*~~
R3.		The responsible entity has maintenance strategies or documented procedures or	The responsible entity has maintenance strategies or documented procedures or	The responsible entity does not have any maintenance strategies or documented

		processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice

	line, line miles or kilometers, etc.)	units of choice - circuit, pole line, line miles or kilometers, etc.).	units of choice - circuit, pole line, line miles or kilometers, etc.).	- circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New

2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

⁺ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)⁺	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

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[20] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[21] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[23] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators may designate lines below 200 kV~~-~~, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, ~~to become elements of an IROL or Major WECC Transfer Path~~ in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC Transfer Path~~ may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an ~~IROL~~ identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the ~~S~~standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer Path~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~pursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths~~.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~that is an element of an IROL or a Major WECC Transfer Path~~ is a greater risk to the interconnected electric transmission system than applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such. Applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

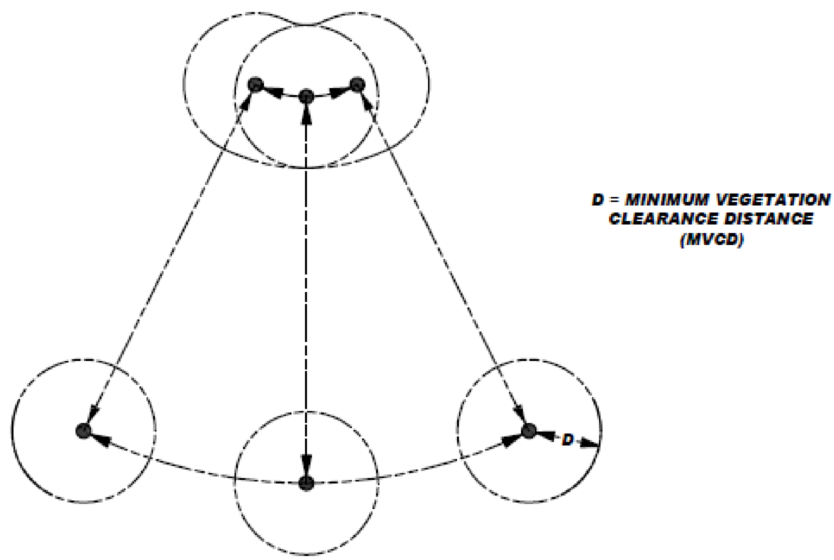

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1~~ and R2~~:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. **Number:** FAC-013-3

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessments.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
Complaints

Violation Severity Levels

<table>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td><td>The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology:
• Part 1.1
• Part 1.3
• Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology:
• Part 1.1
• Part 1.3
• Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator did not have a Transfer Capability methodology.
OR
The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology:
• Part 1.1
• Part 1.3
• Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.</td></tr>
</table>

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
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SAR posted for comment	08/20/15 – 09/21/15

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NERC Board adoption	November 2018

New or Modified Term(s) Used in NERC Reliability Standards

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Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
2. **Number:** FAC-013-3~~2~~
3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.
4. **Applicability:**
   4.1. Planning Coordinators
5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use~~A statement that the assessment shall respect known System Operating Limits (SOLs)~~.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning~~planning~~ Assessments~~practices~~.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” Added or removed “periods.”	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF’s for Requirements R1. and R4. be changed from “Lower” to “Medium.” FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-3

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator’s historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

High Level Requirement Overview

[1] “OPEN” and “CLOSE” are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3~~2~~
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator**~~

~~**4.1.3** Western Interconnection – Reliability Coordinator~~

~~**4.1.4** Quebec Interconnection – Planning Coordinator or Reliability Coordinator~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, ~~Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC | ~~RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-5
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used

exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-54
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used

exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

~~**B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to any generating output limitation or RAS. A stability constraint limits the output of the portion of the

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[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

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[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay’s susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

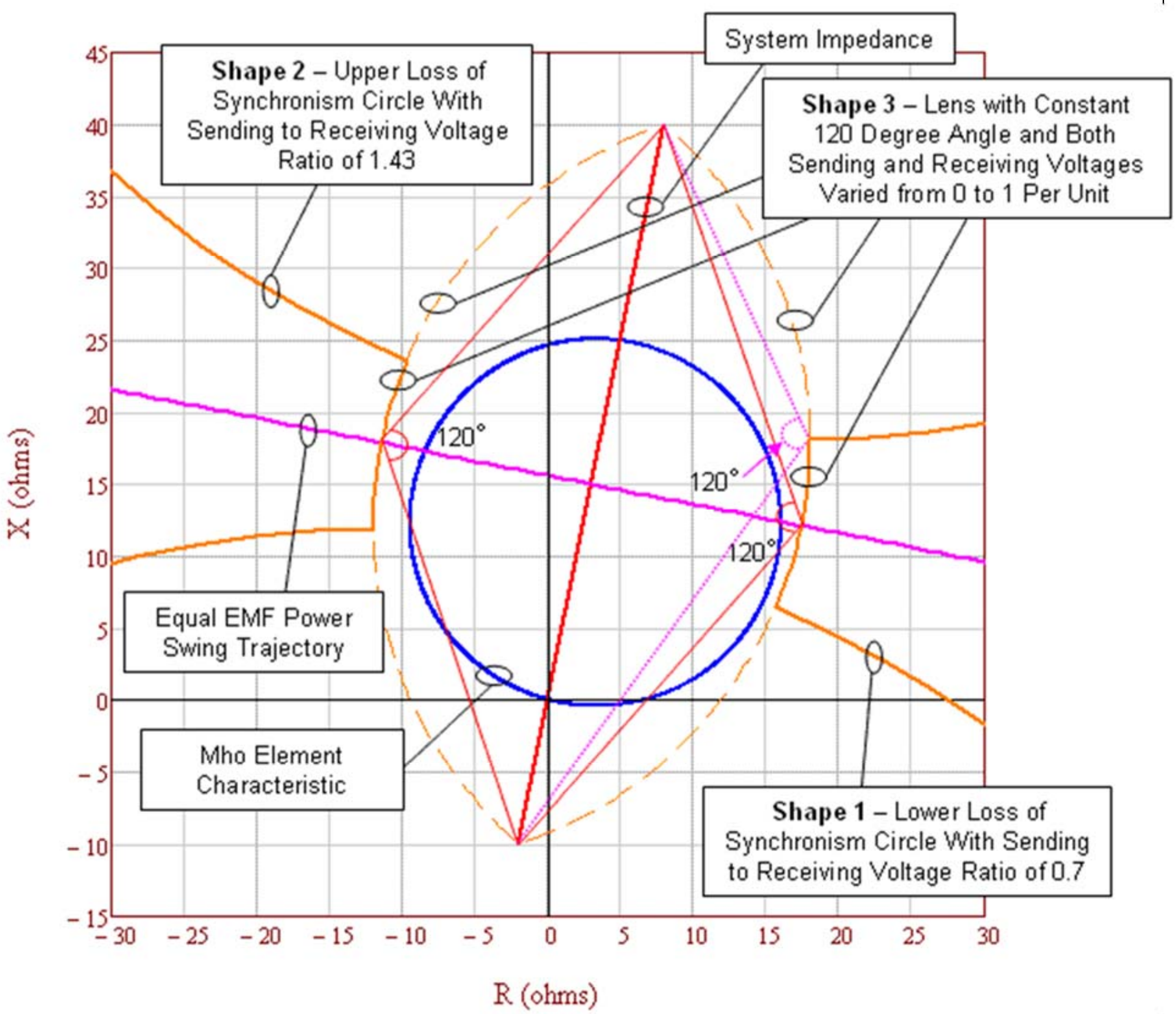


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

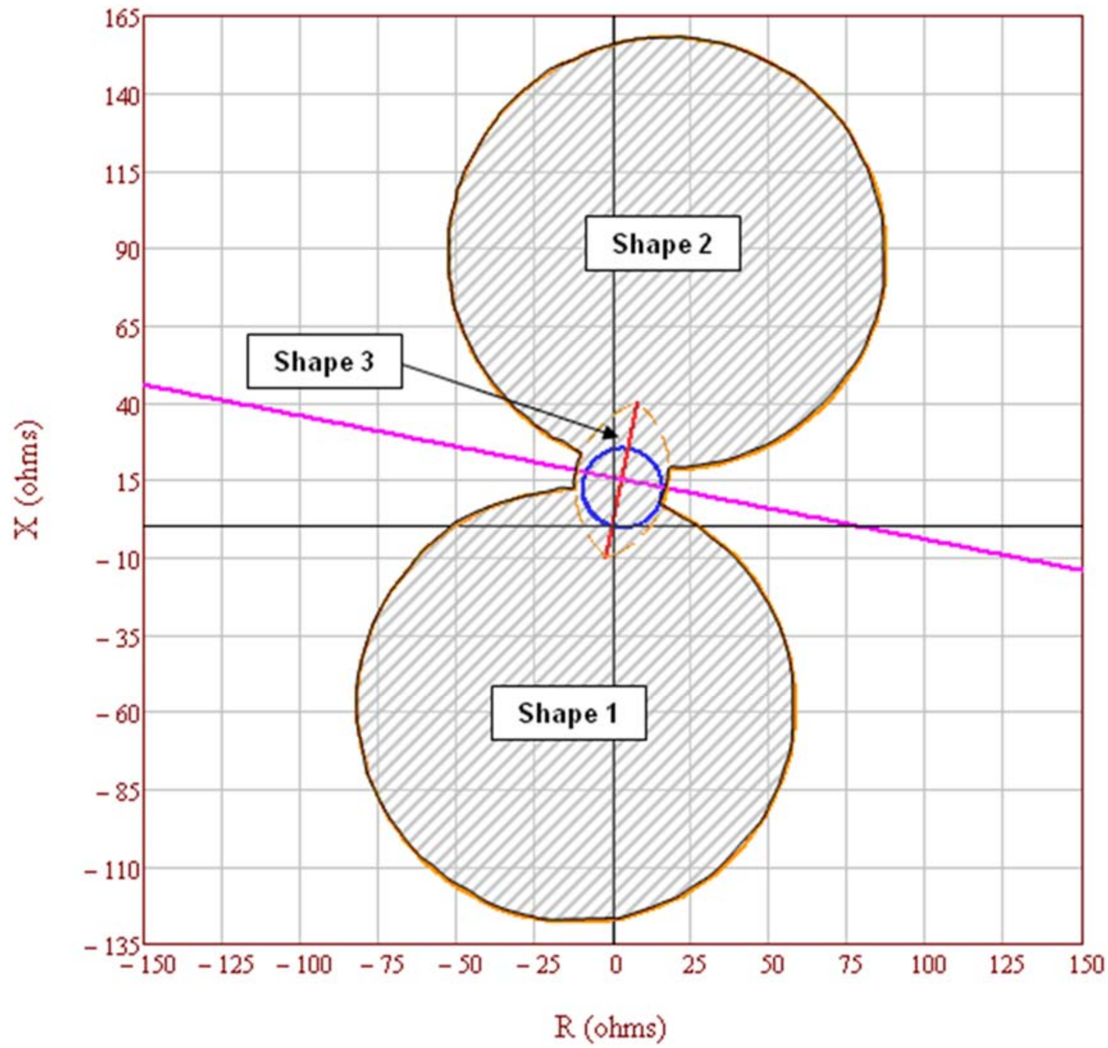


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

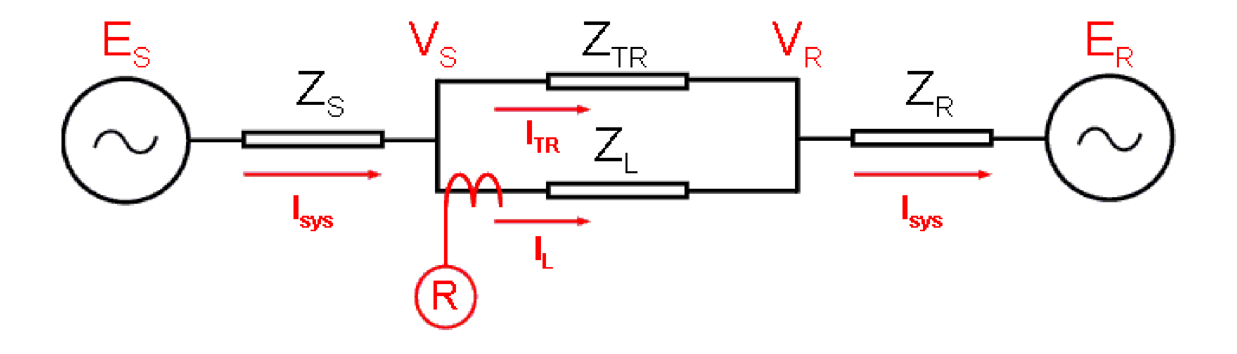


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

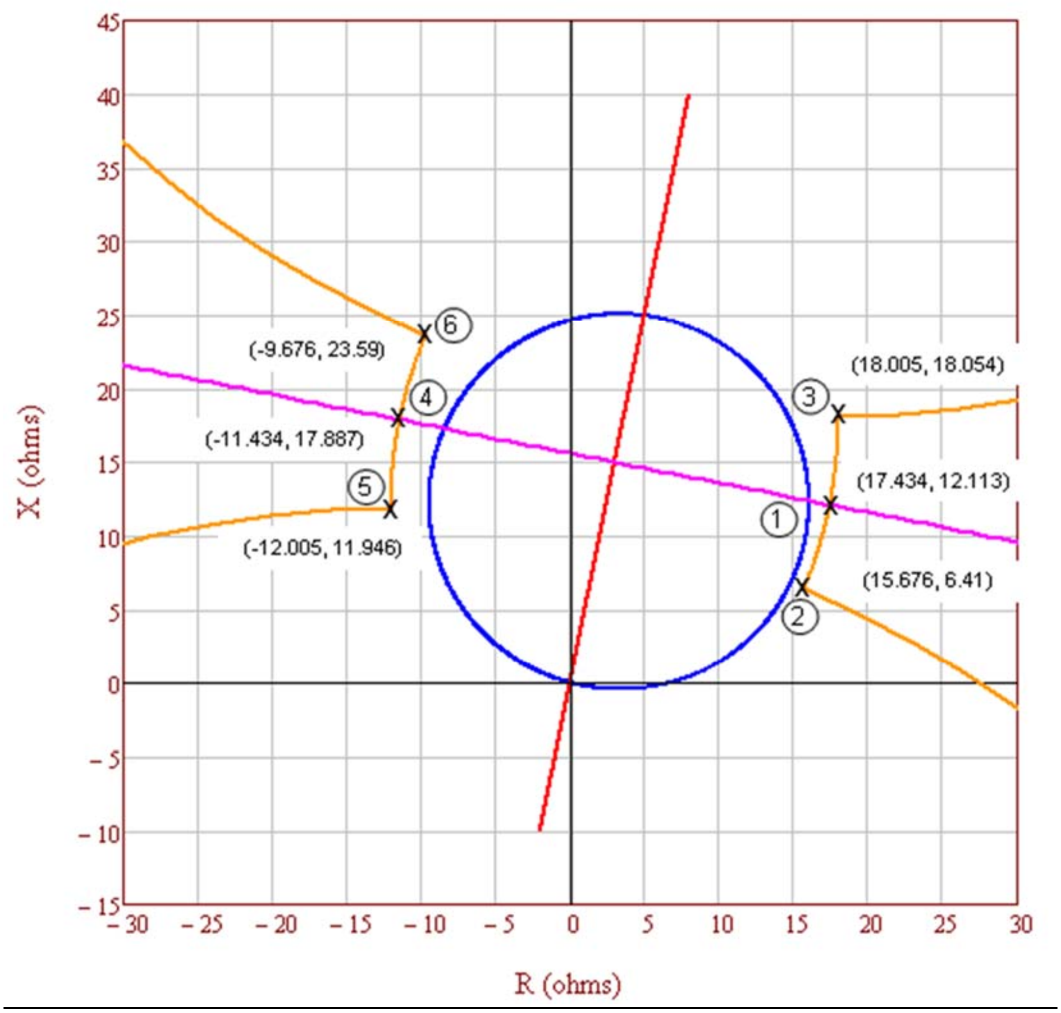


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20)\times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10+j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4+j20)\times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2+j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

<table>
<tr><th colspan="4">Table 4: Example Calculation (Lens Point 3)</th></tr>
<tr><td colspan="4">This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.</td></tr>
<tr><td>Eq. (22)</td><td colspan="3">$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$</td></tr>
<tr><td></td><td colspan="3">$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$</td></tr>
<tr><td></td><td colspan="3">$E_S = 132{,}791\angle 120°\ V$</td></tr>
<tr><td>Eq. (23)</td><td colspan="3">$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$</td></tr>
<tr><td></td><td colspan="3">$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$</td></tr>
<tr><td></td><td colspan="3">$E_R = 92{,}953.7\angle 0°\ V$</td></tr>
<tr><td colspan="4">Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).</td></tr>
<tr><td>Given:</td><td>$Z_S = 2 + j10\ \Omega$</td><td>$Z_L = 4 + j20\ \Omega$</td><td>$Z_R = 4 + j20\ \Omega$</td></tr>
<tr><td>Given:</td><td colspan="3">$Z_{TR} = Z_L \times 10^{10}\ \Omega$</td></tr>
<tr><td colspan="4">Total impedance between the generators.</td></tr>
<tr><td>Eq. (24)</td><td colspan="3">$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$</td></tr>
<tr><td></td><td colspan="3">$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$</td></tr>
<tr><td></td><td colspan="3">$Z_{total} = 4 + j20\ \Omega$</td></tr>
<tr><td colspan="4">Total system impedance.</td></tr>
<tr><td>Eq. (25)</td><td colspan="3">$Z_{sys} = Z_S + Z_{total} + Z_R$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = 10 + j50\ \Omega$</td></tr>
</table>

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

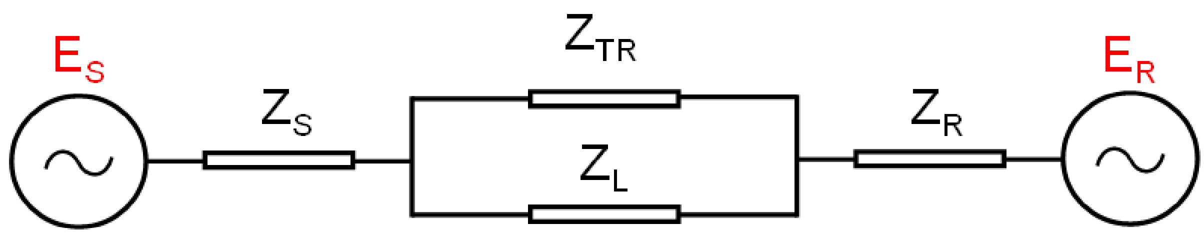
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}511\angle 131.1°\ A]$
	$V_S = 95{,}756\angle -106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1°\ V}{4{,}511\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

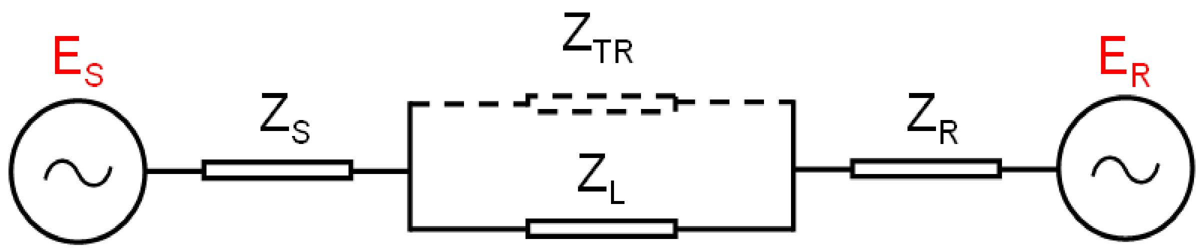
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle - 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

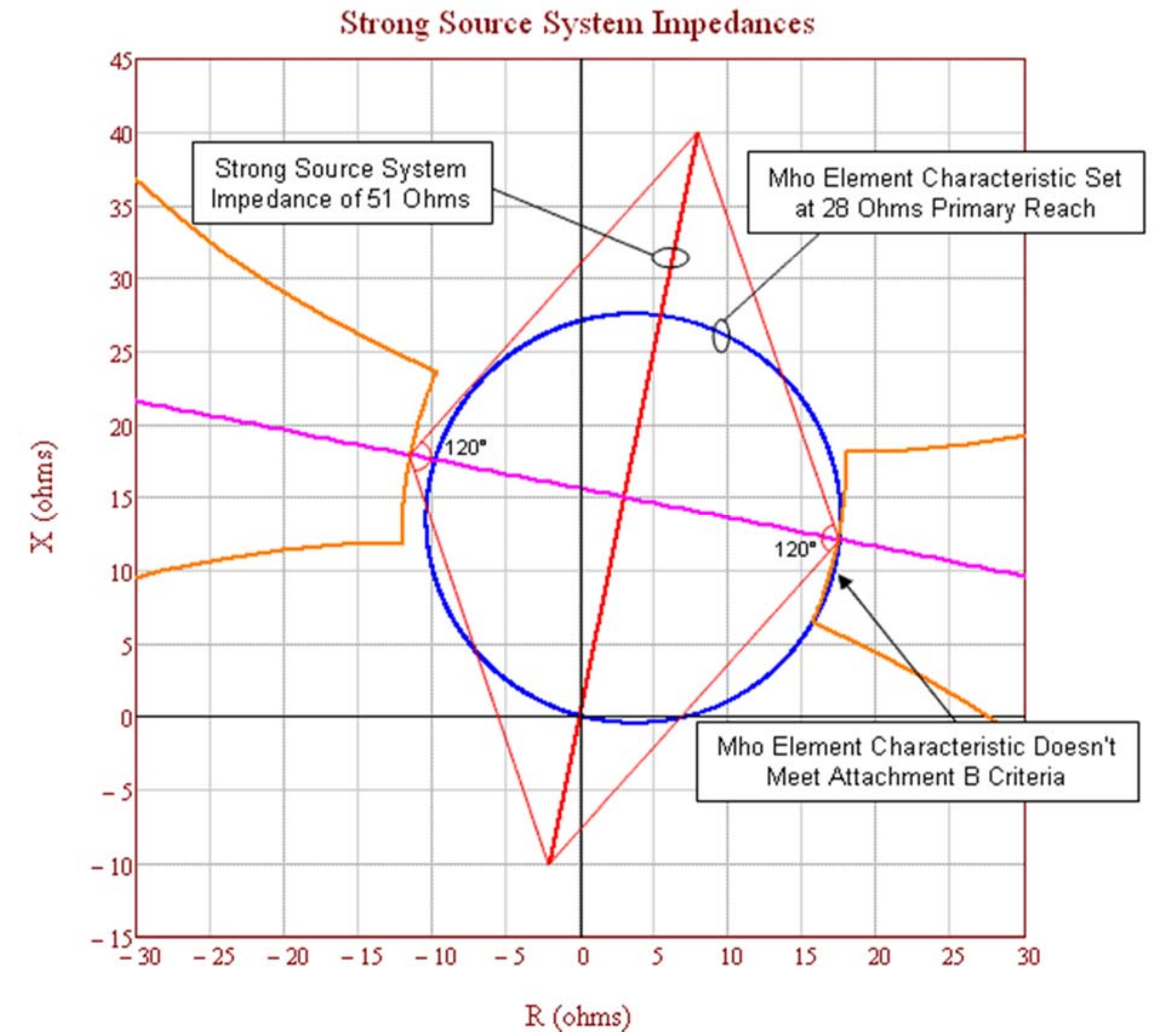


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

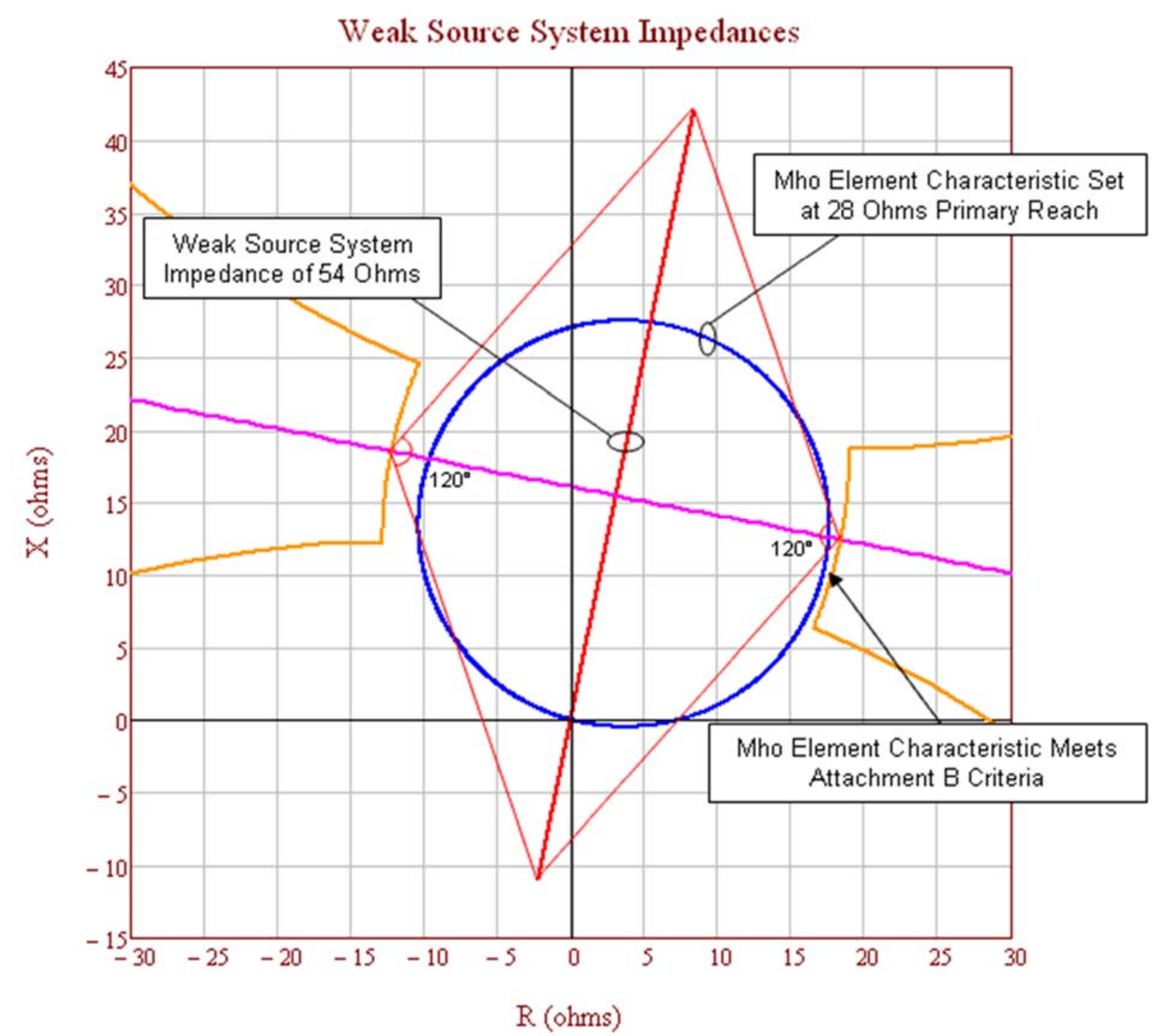


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

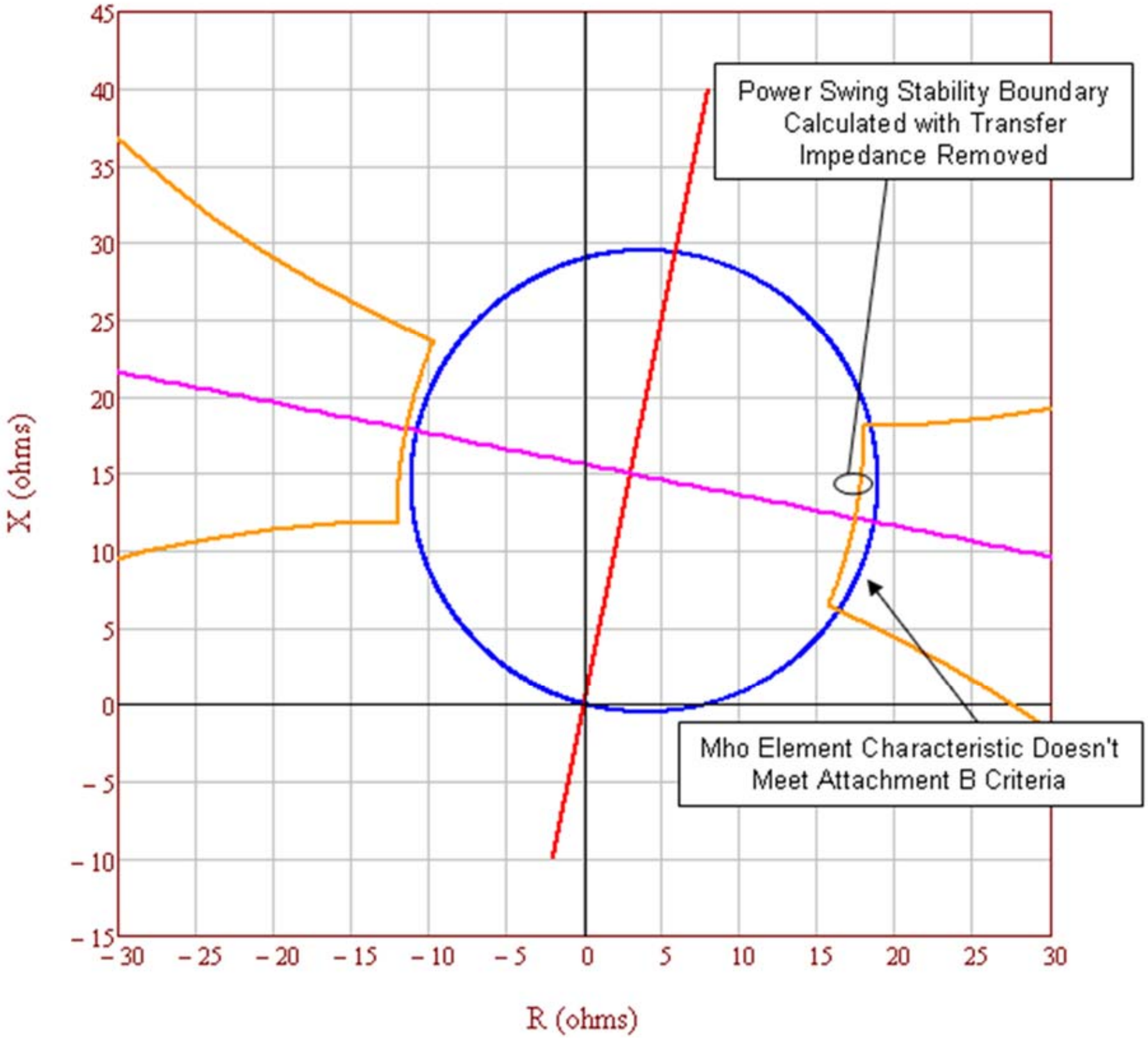


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

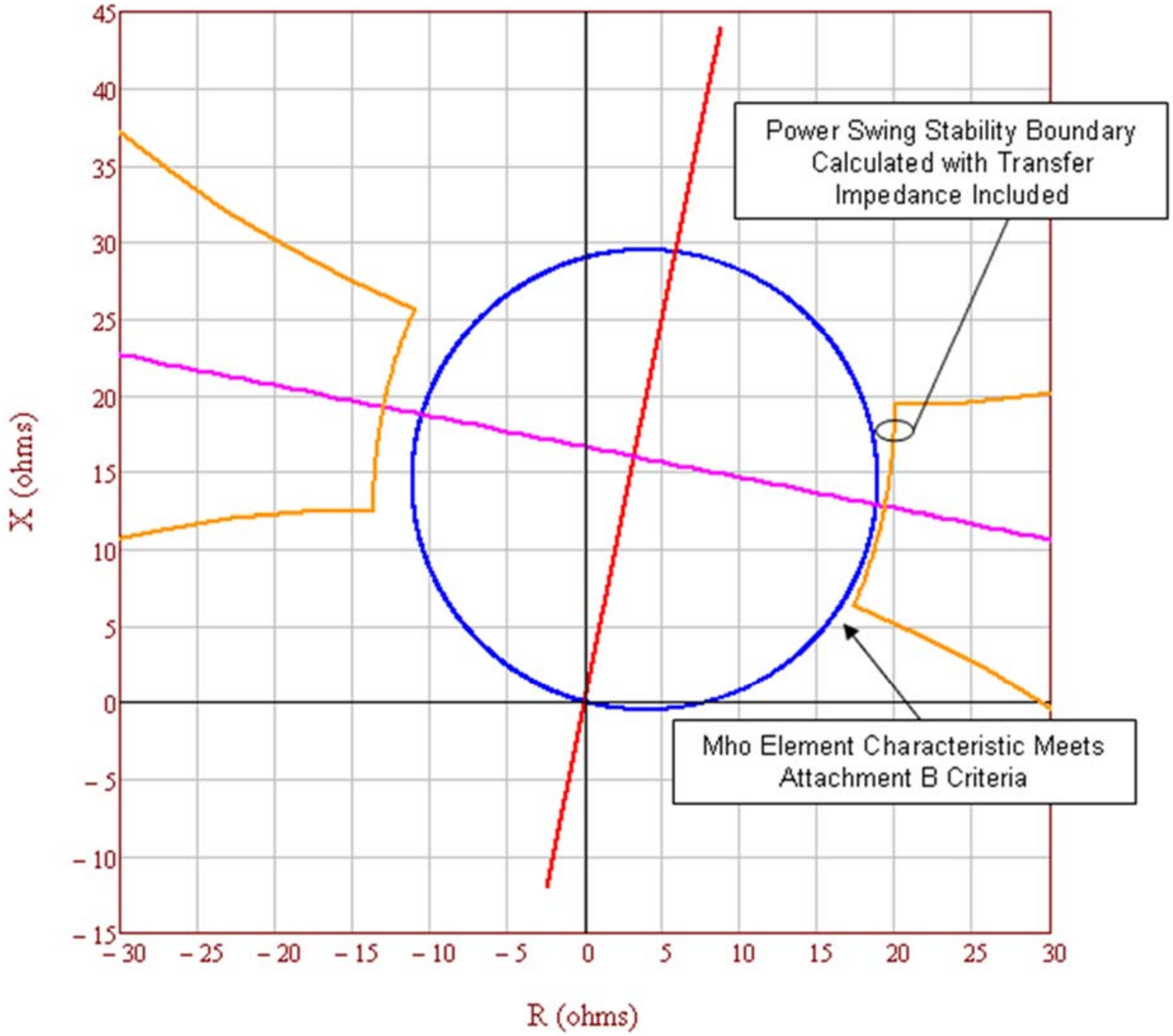


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\,V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\,V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\,V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\,V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\,\Omega \times 5$		
	$Z_{TR} = 20 + j100\,\Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\,\Omega \times (20 + j100)\,\Omega}{(4 + j20)\,\Omega + (20 + j100)\,\Omega}$		
	$Z_{total} = 3.333 + j16.667\,\Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\,\Omega + (3.333 + j16.667)\,\Omega + (4 + j20)\,\Omega$		
	$Z_{sys} = 9.333 + j46.667\,\Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\,V - 132{,}791\angle 0°\,V}{9.333 + j46.667\,\Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

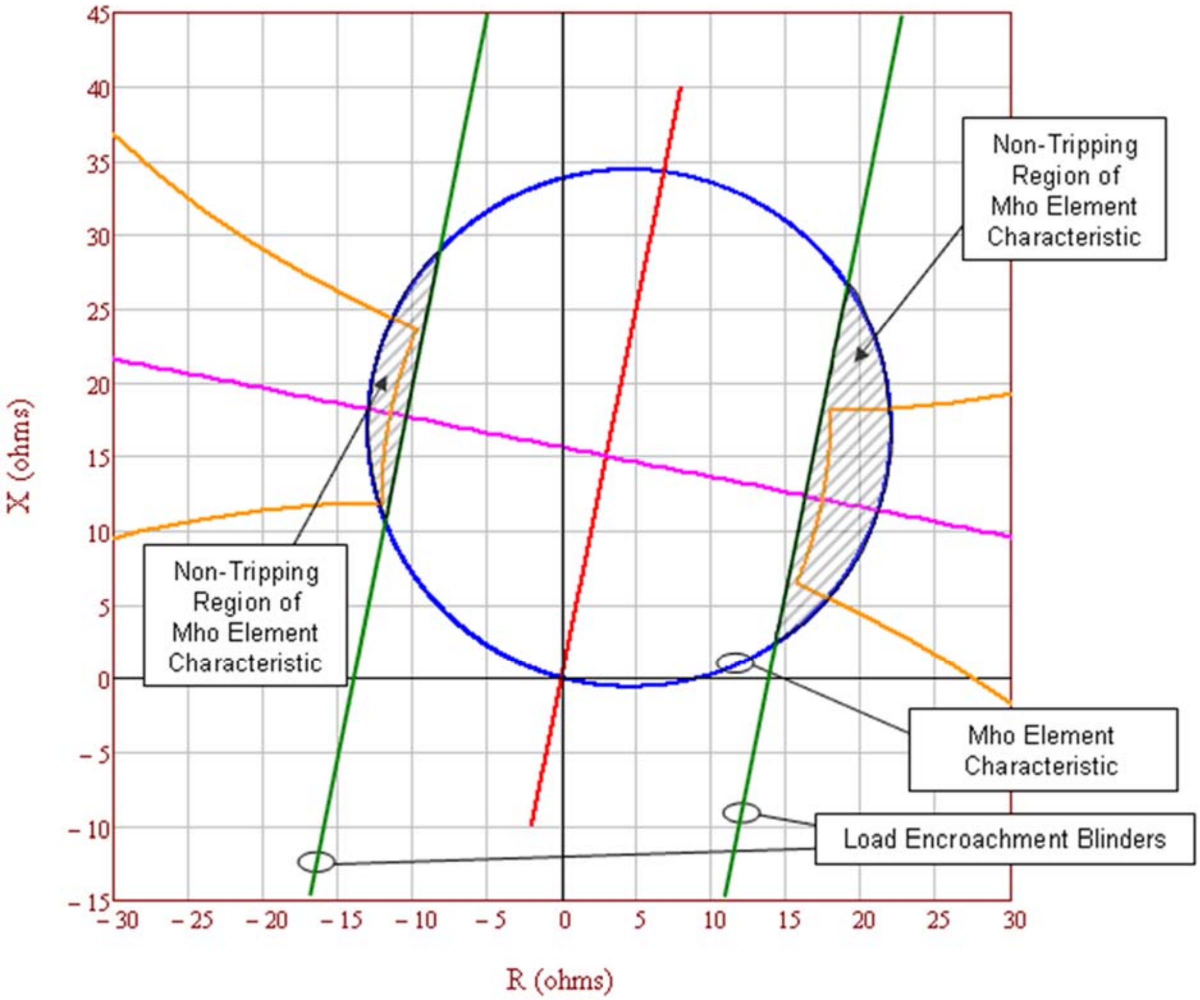


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

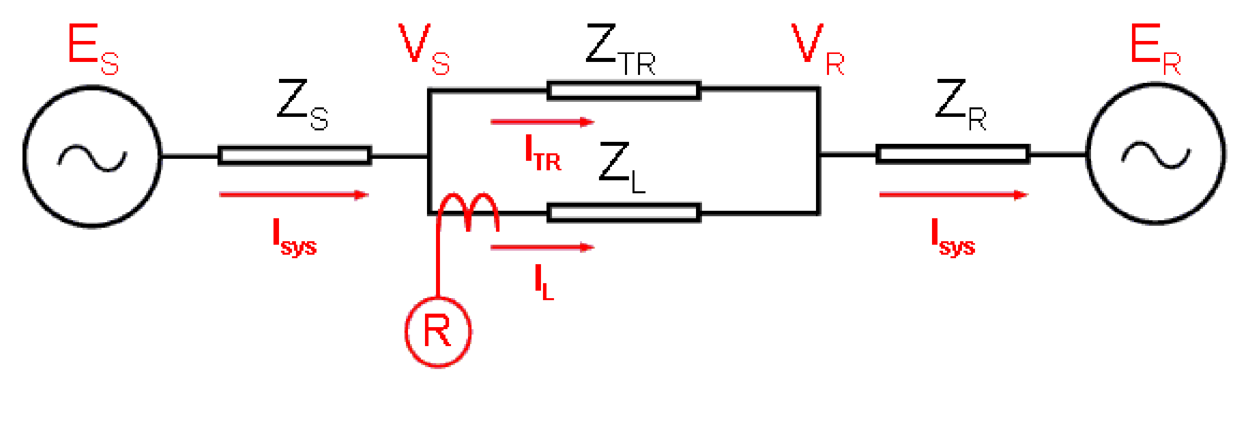


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

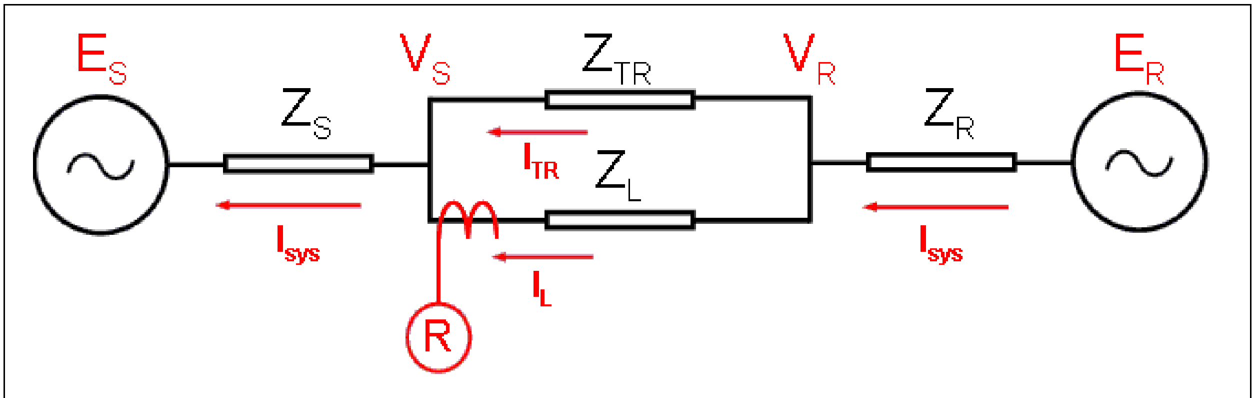


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

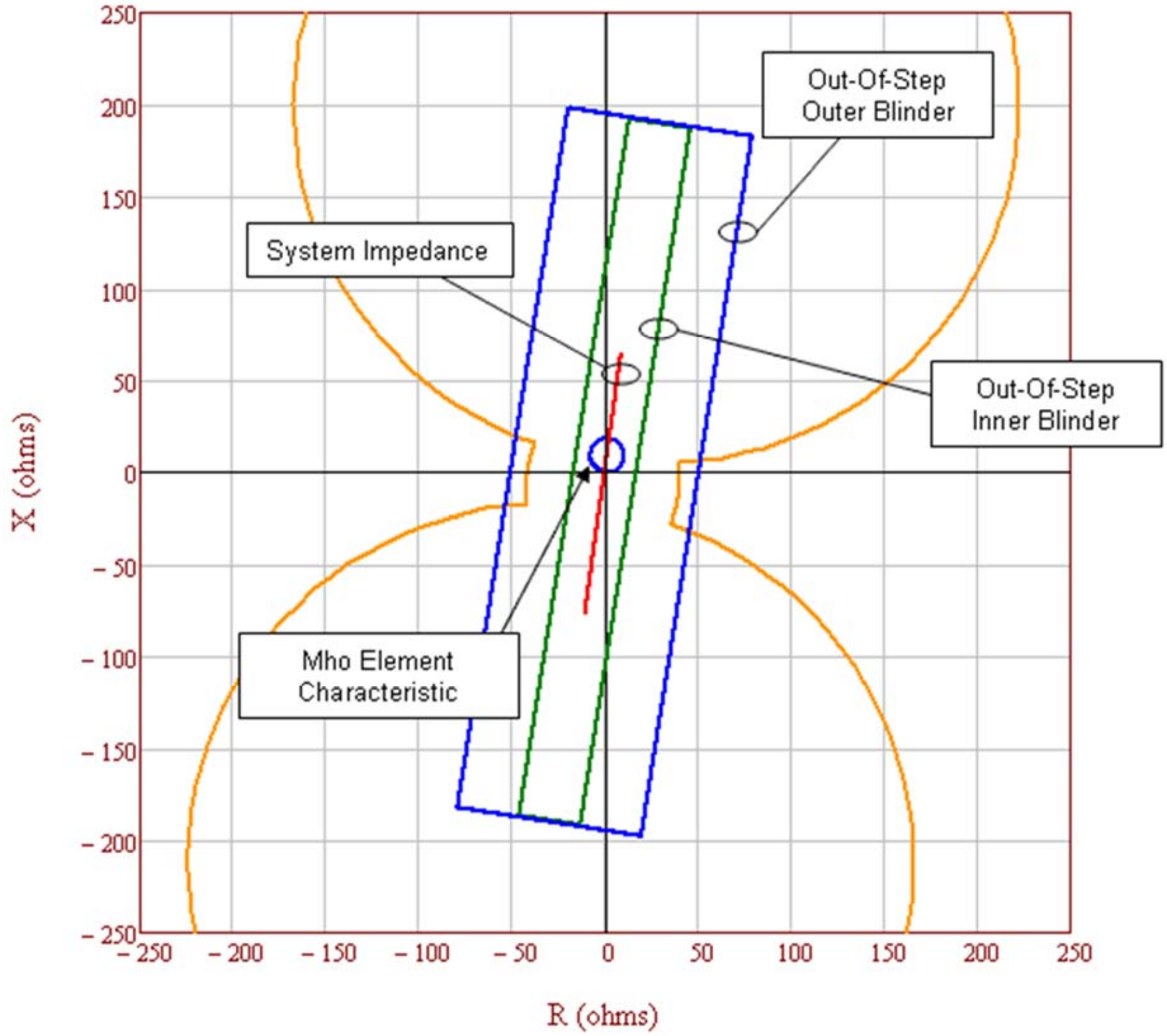


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of $N < 1$ and $N > 1$ as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert\frac{N \times Z_{sys}}{N^2 - 1}\right\rvert$
	$r_b = \left\lvert\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right\rvert$
	$r_b = 69.987\ \Omega$

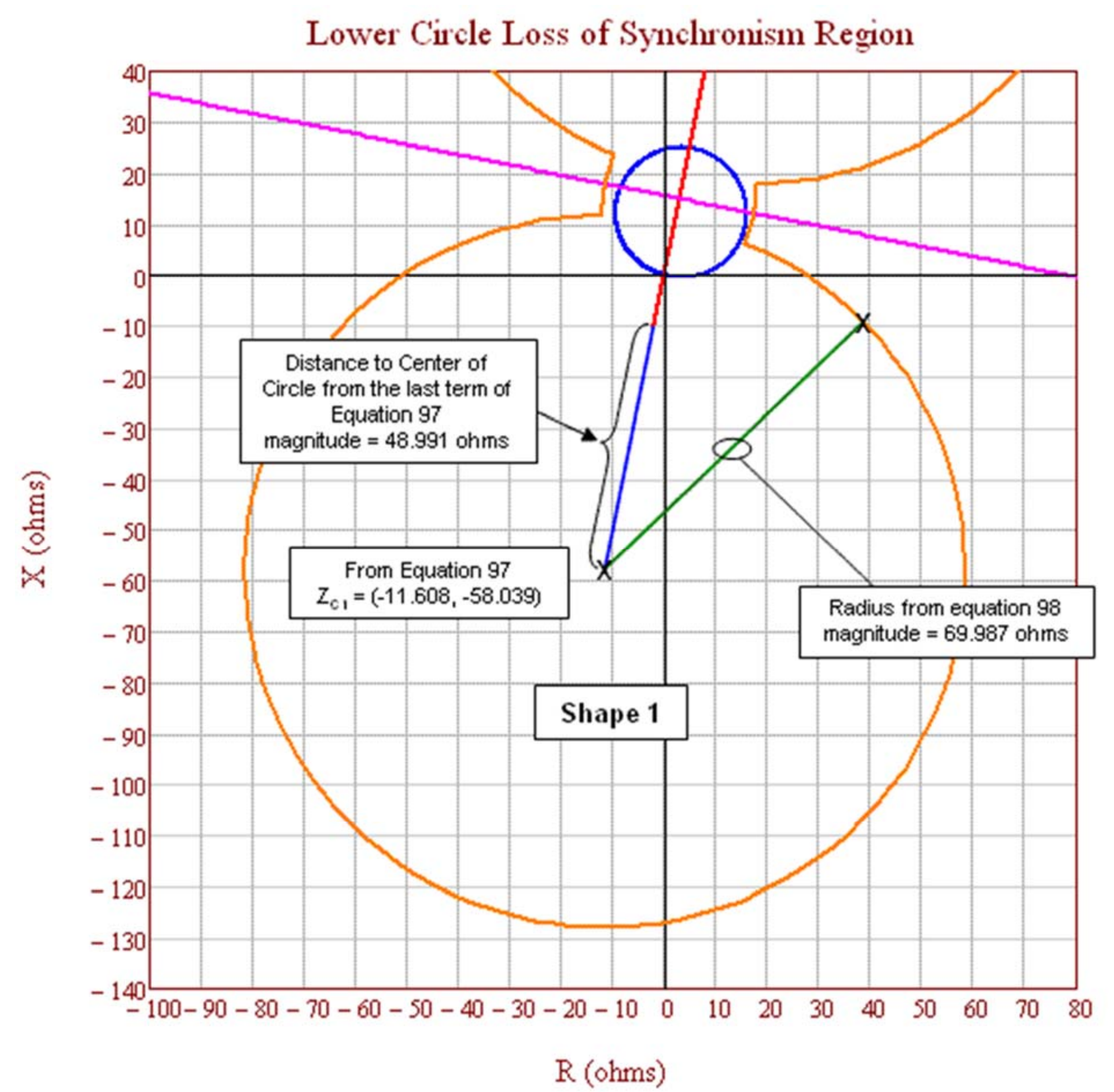


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

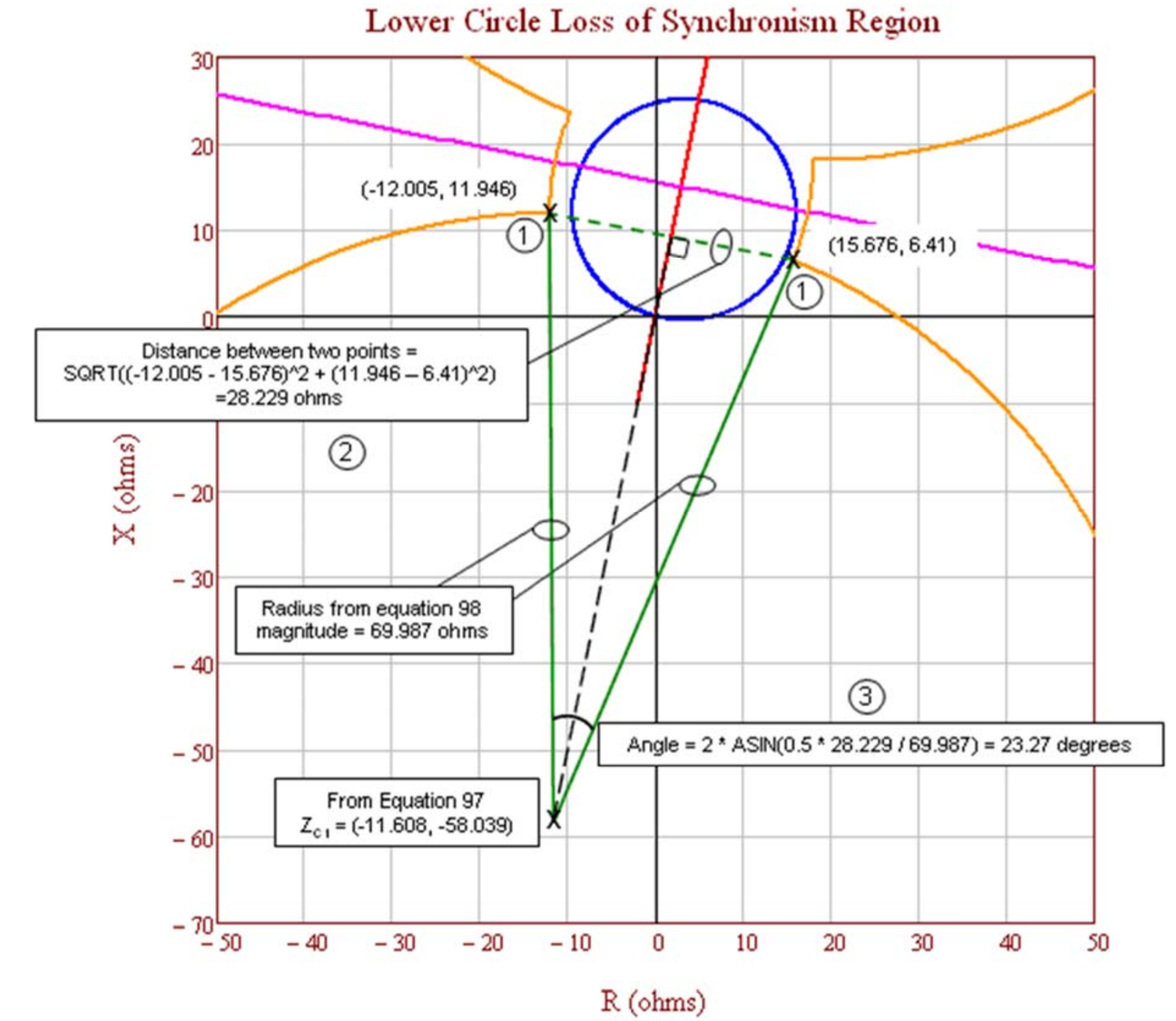


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

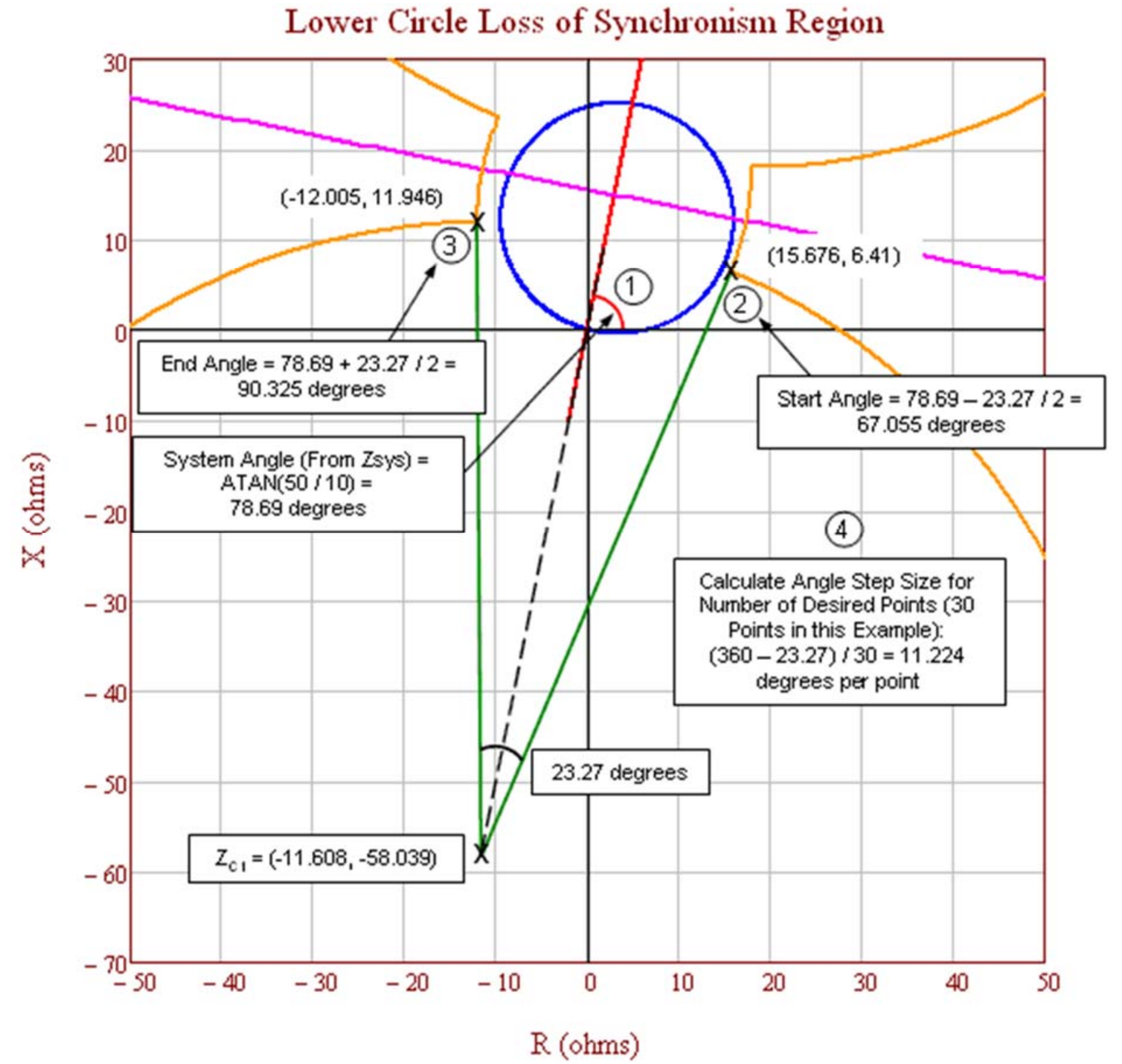


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

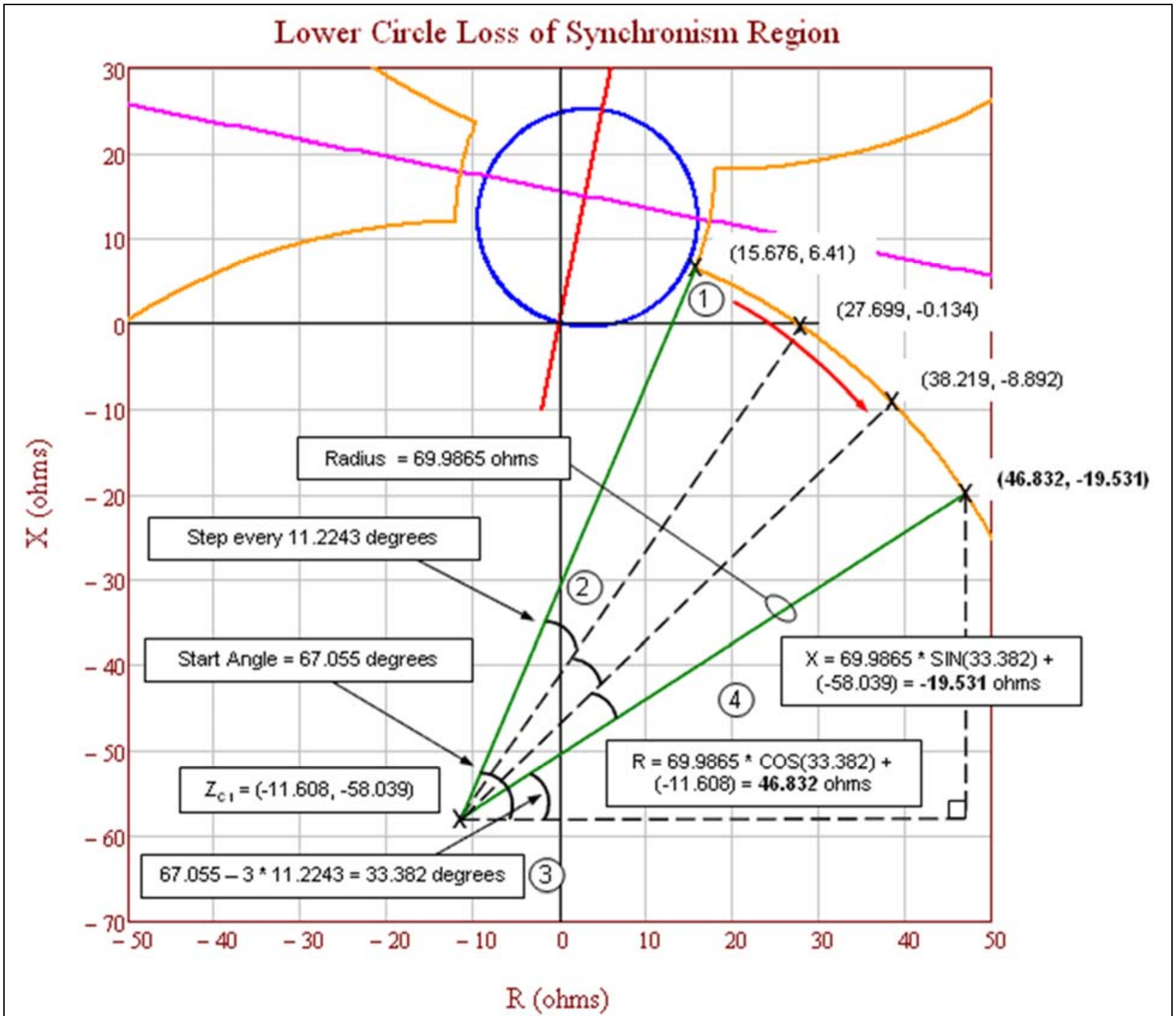


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

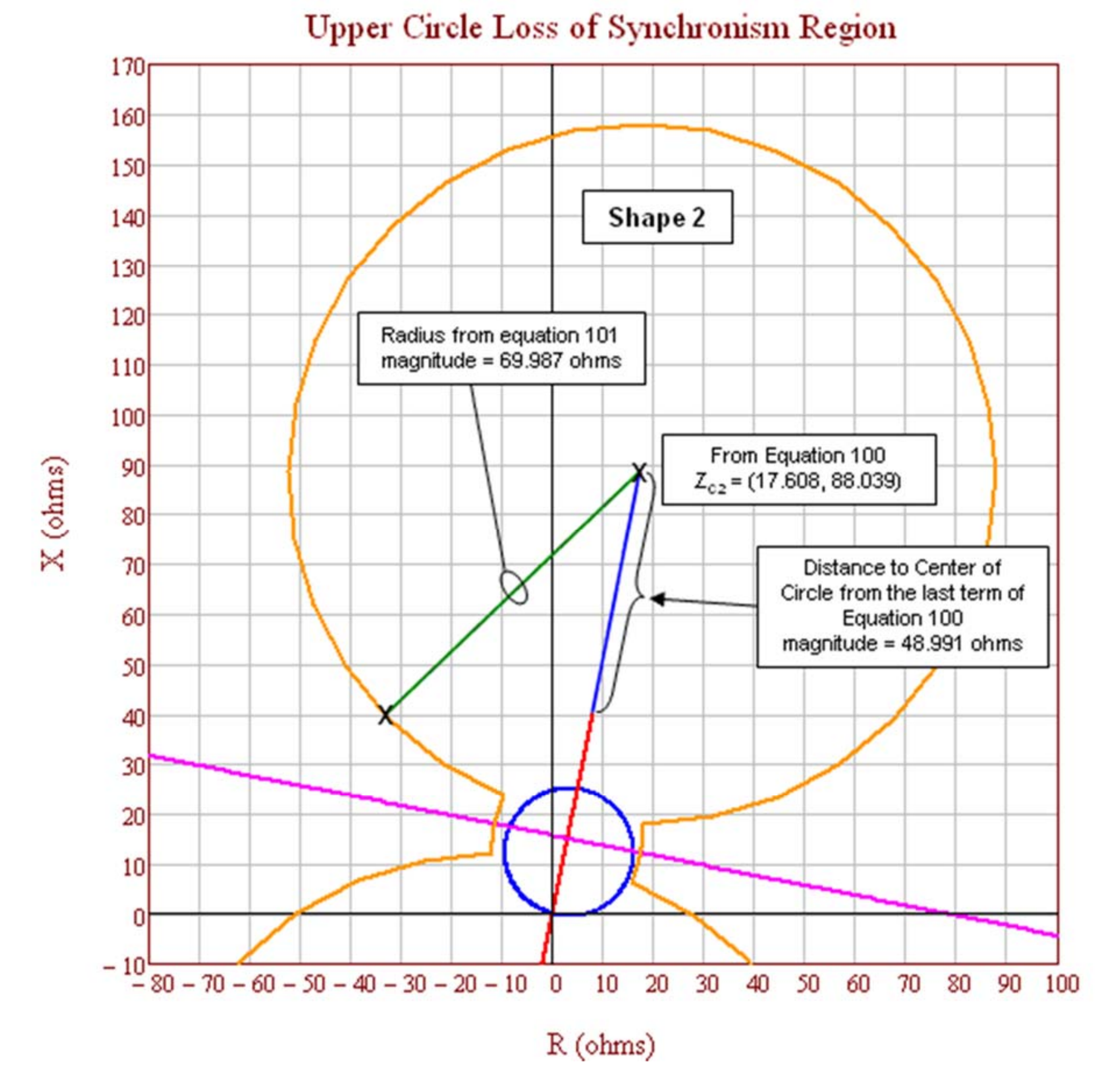


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

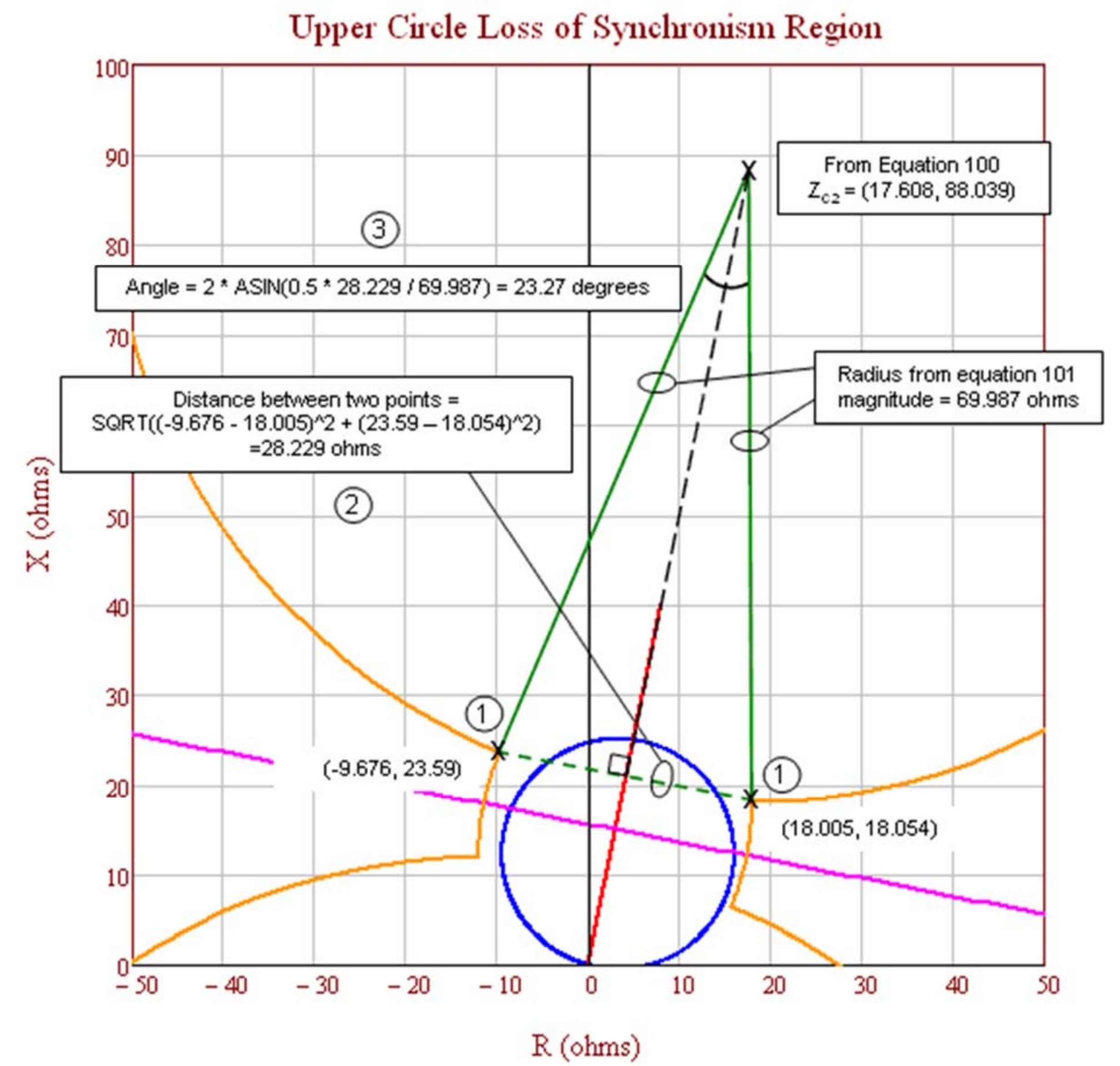


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

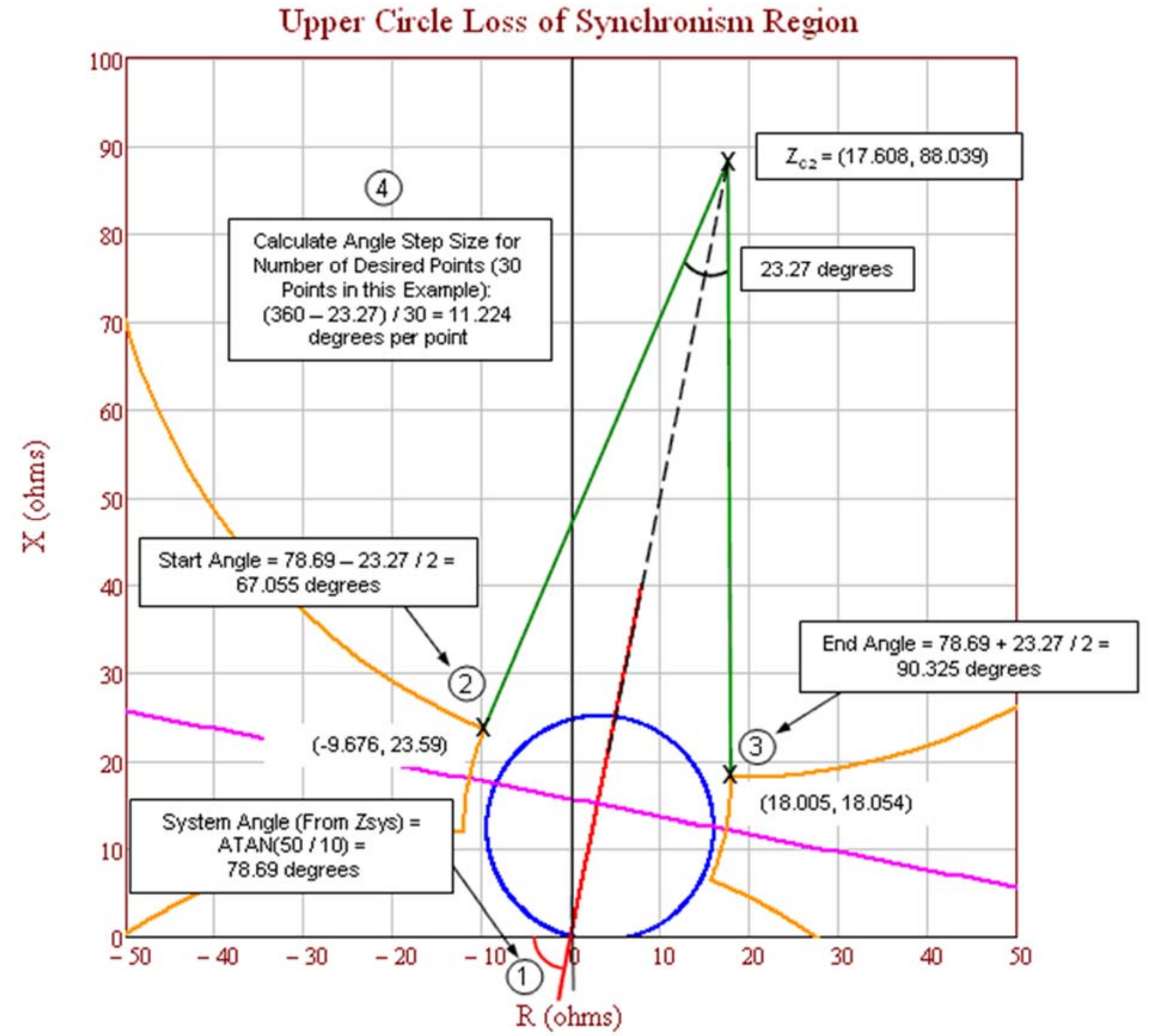


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

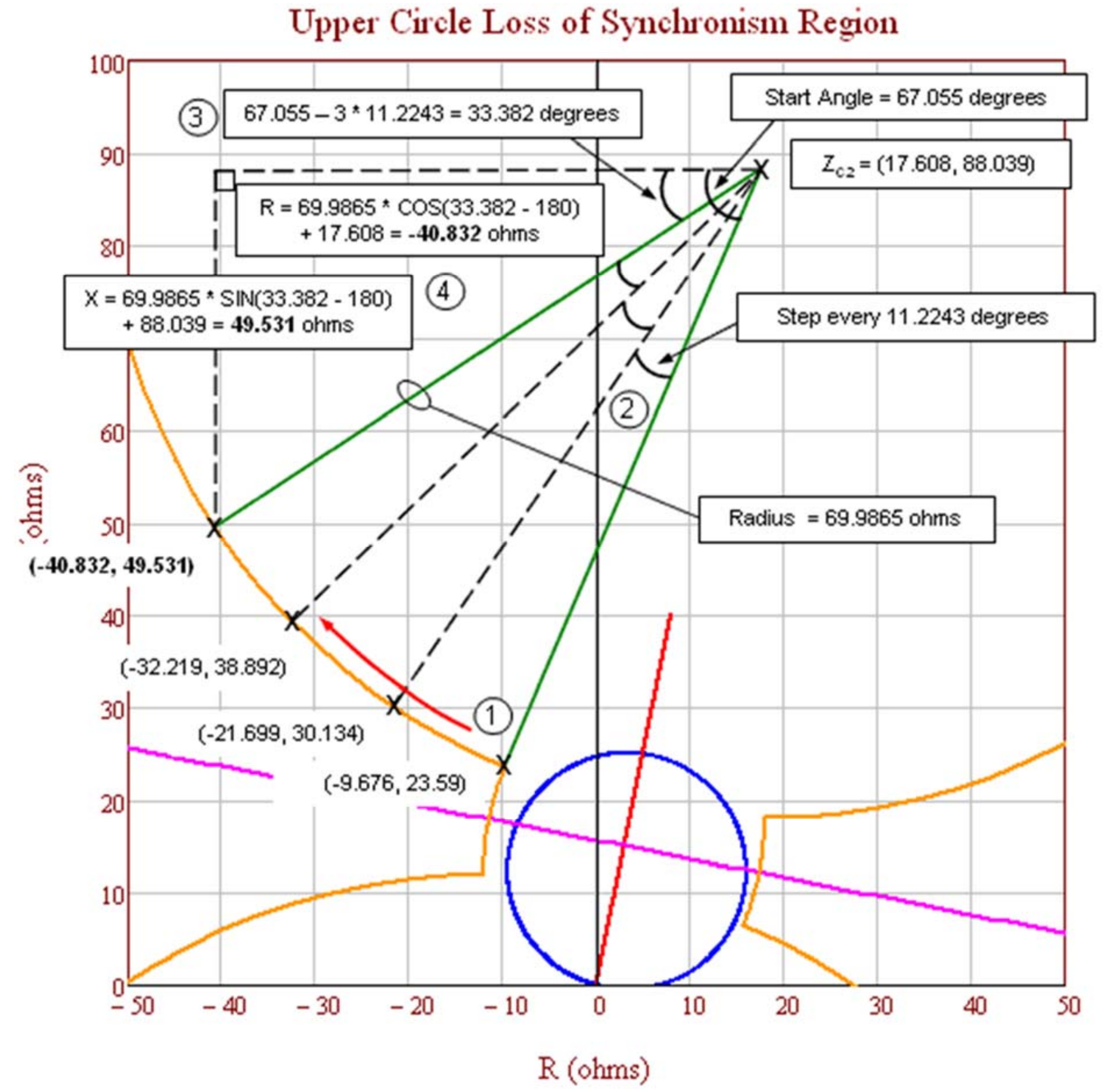


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

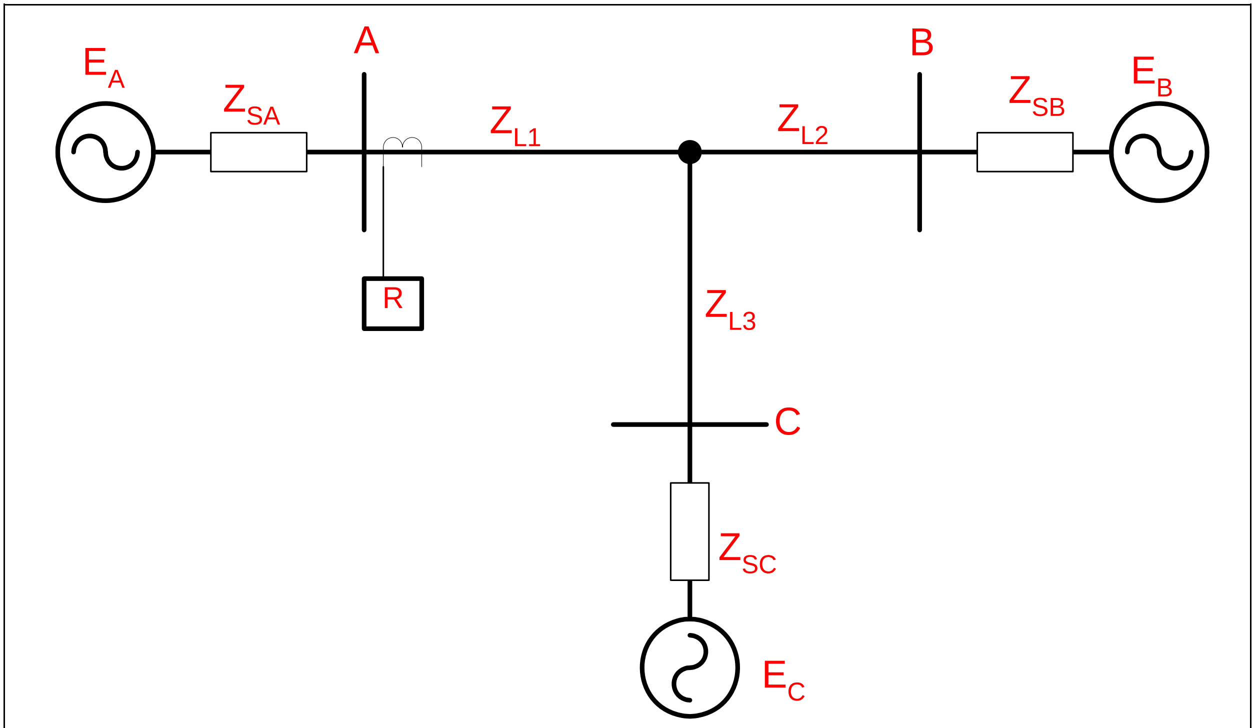


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

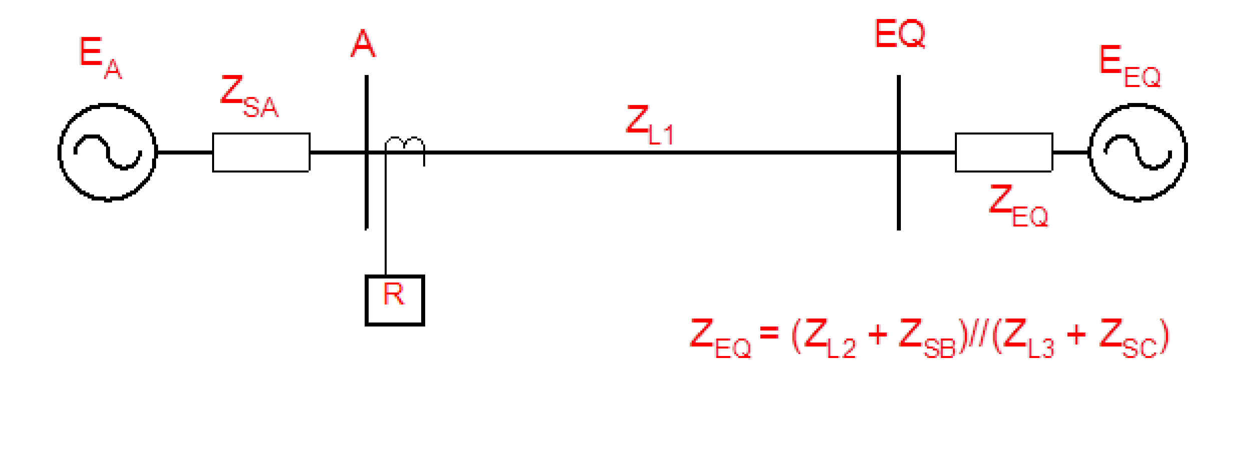


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

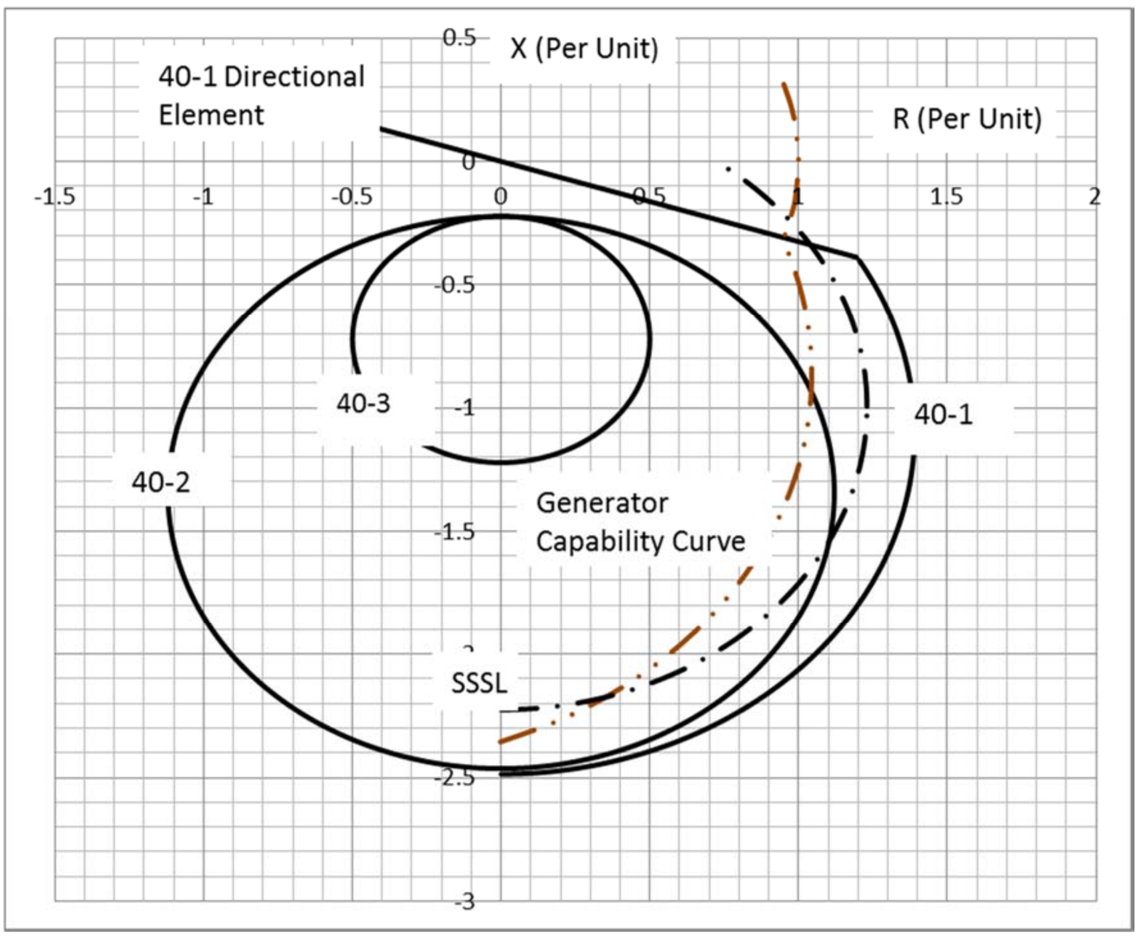


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

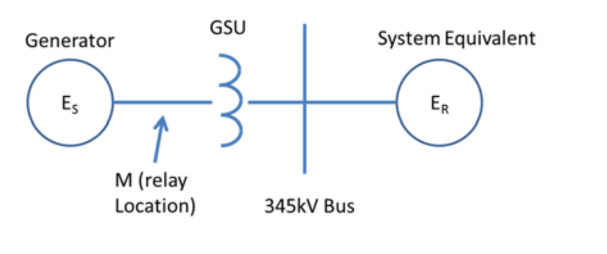

Figure 17: Simple one-line diagram of the system to be evaluated.

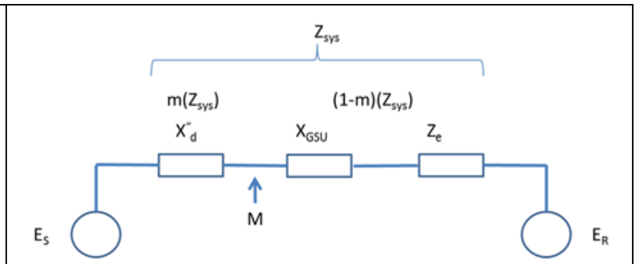

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) $=$ 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter $=$ 0.55 per unit
	MTA $= 85°$

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

Angle (δ) (Degrees)	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

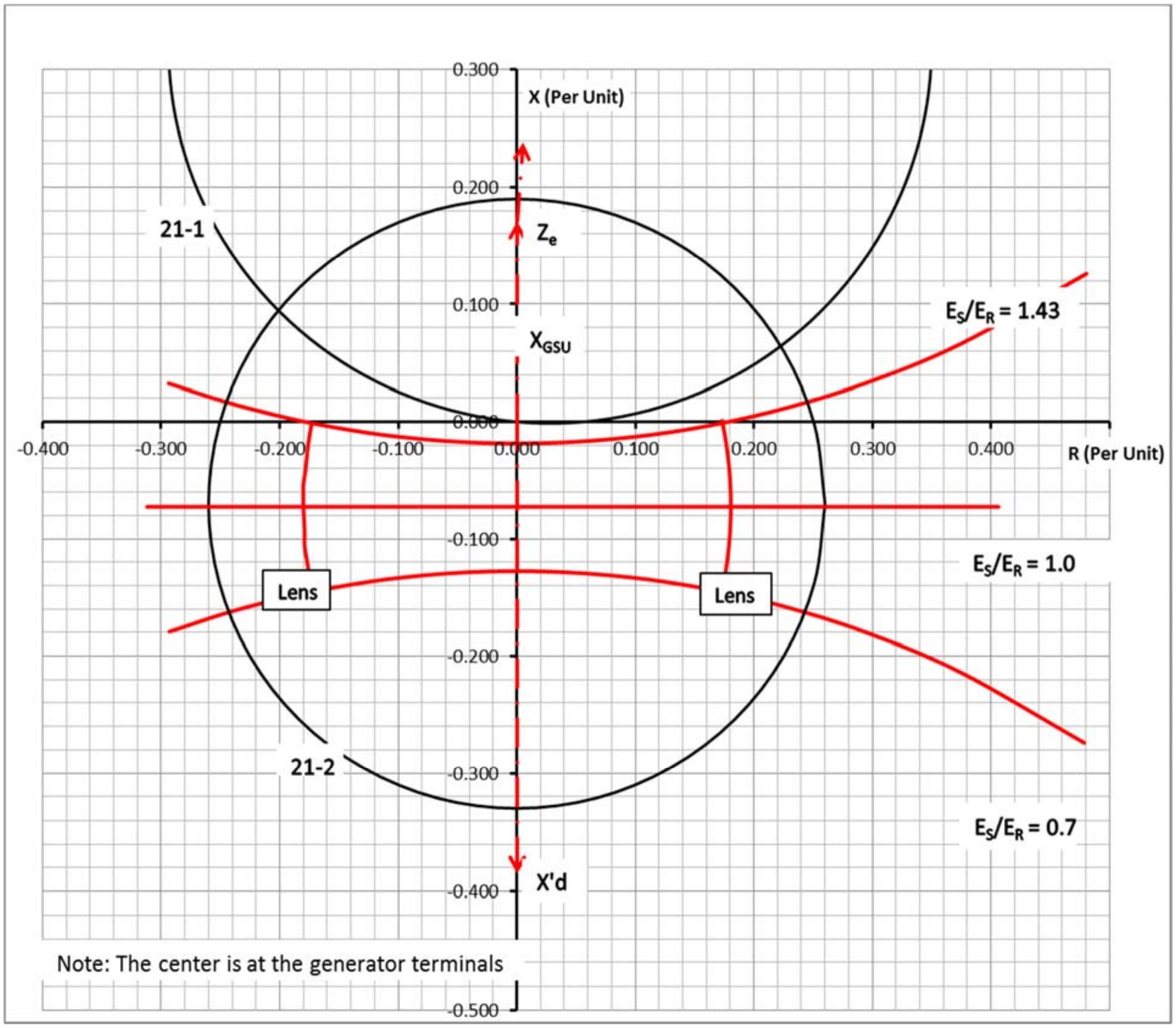

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

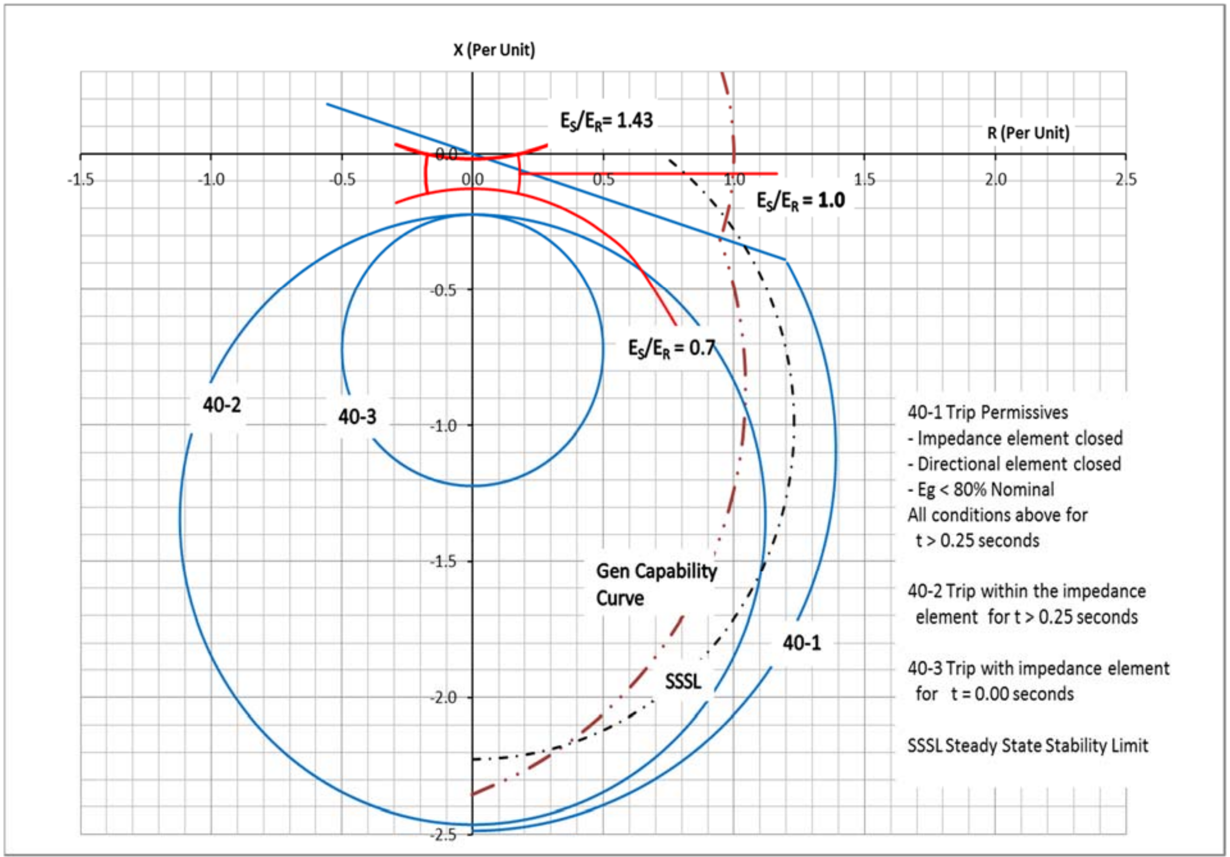

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_{T}), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

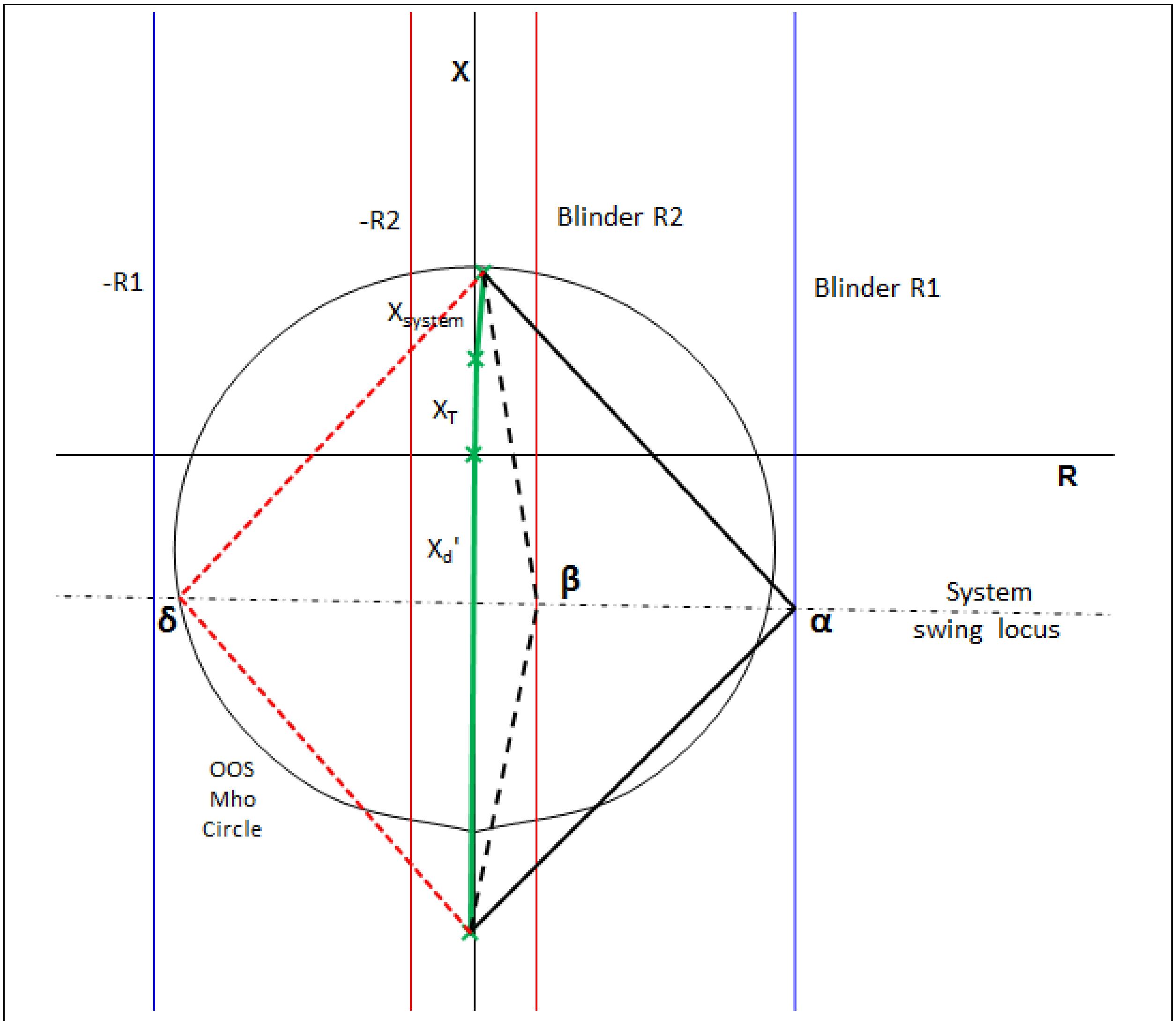

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

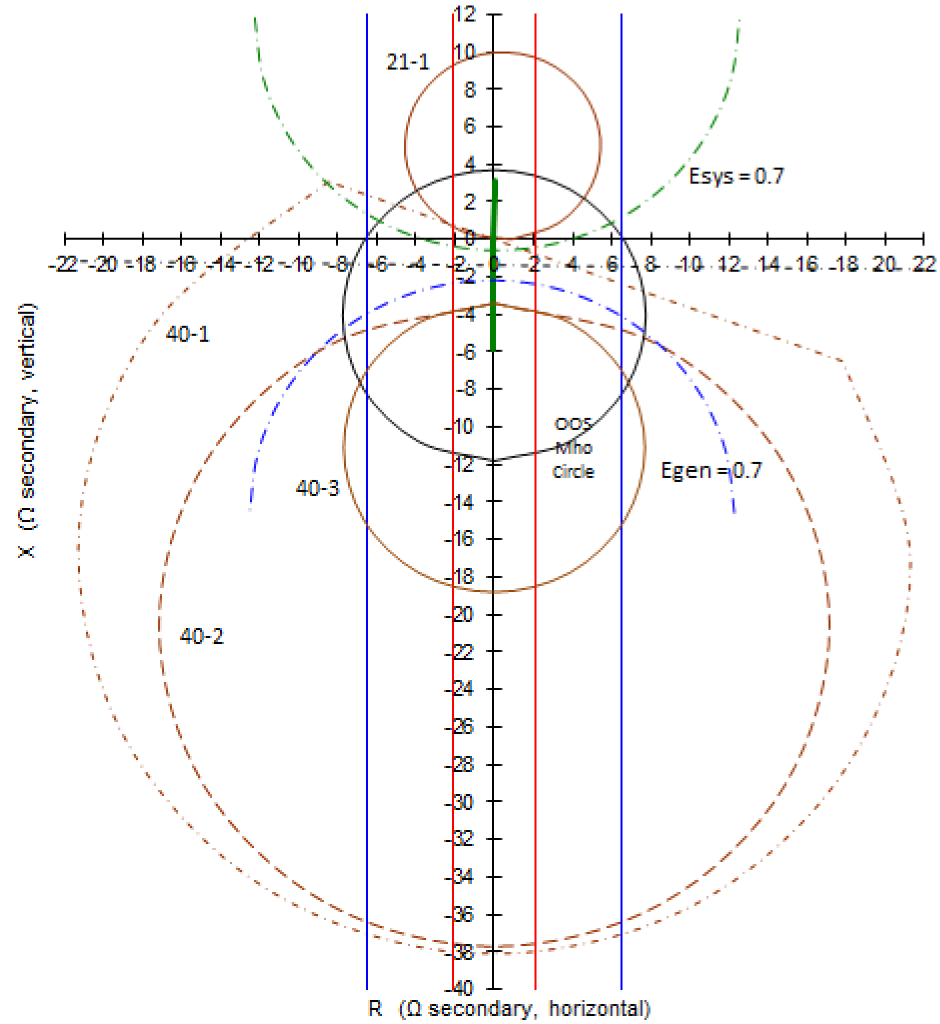

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

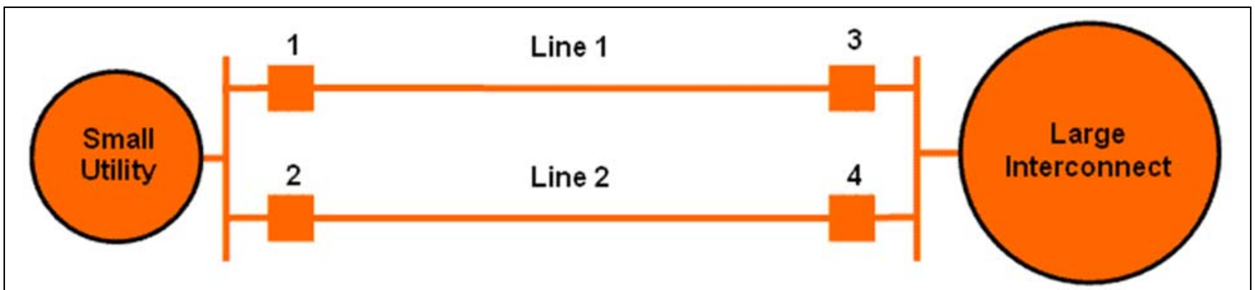

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

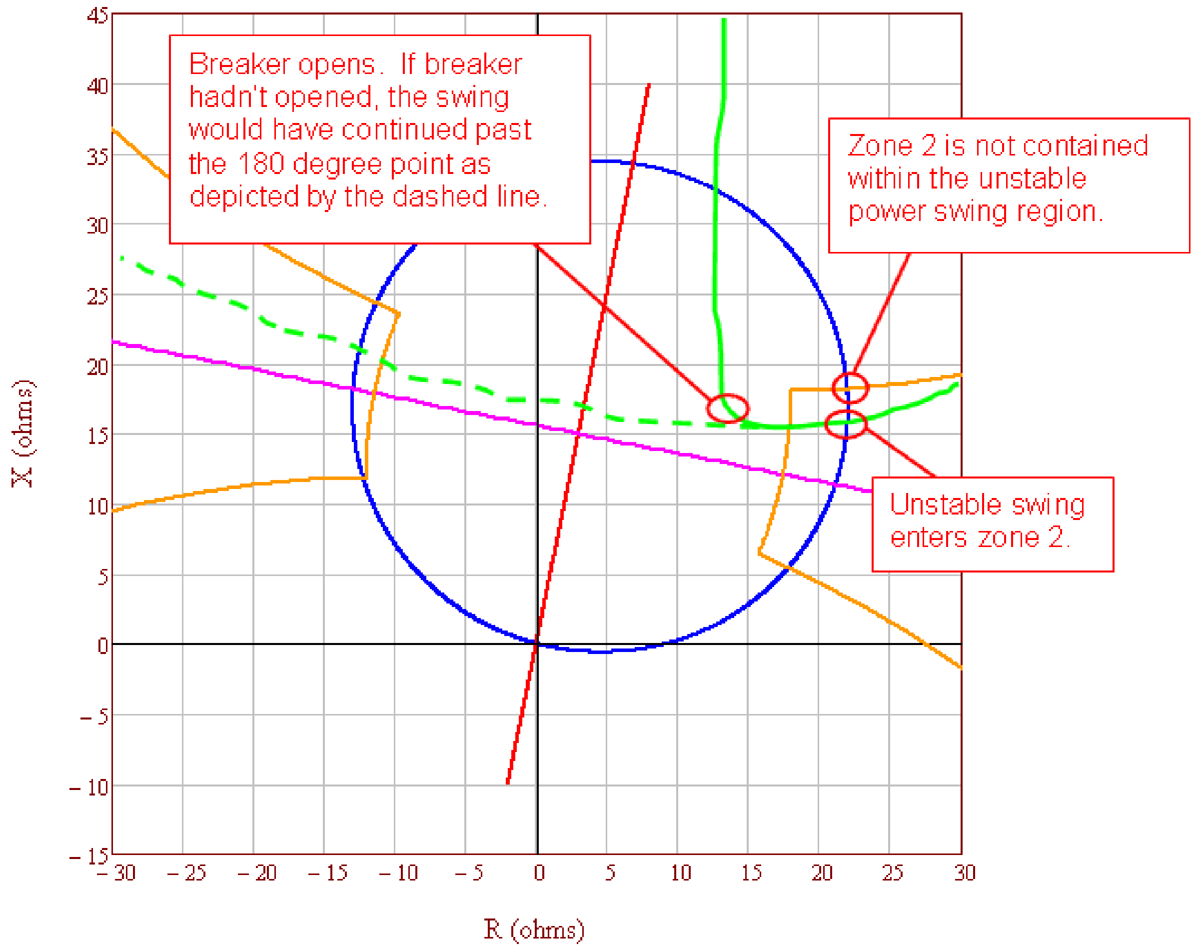

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

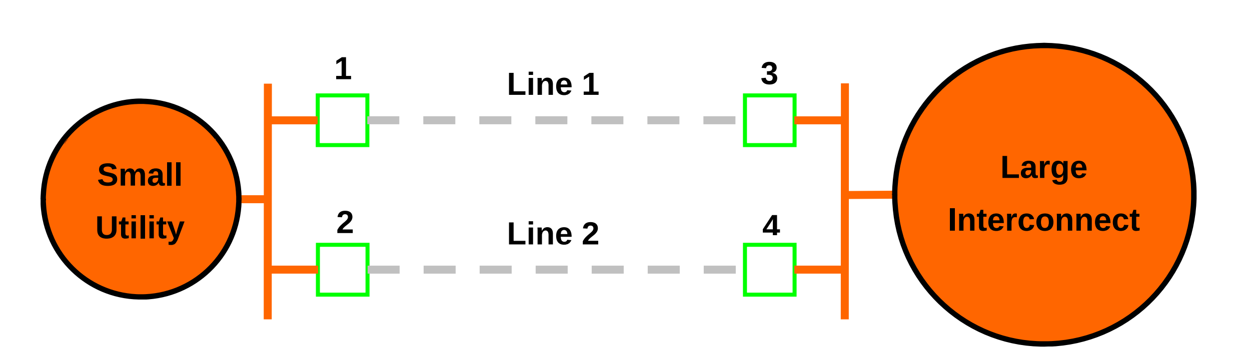

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

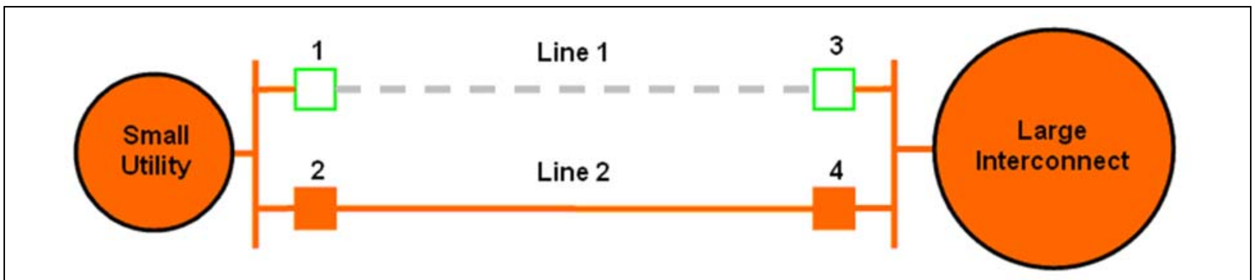

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

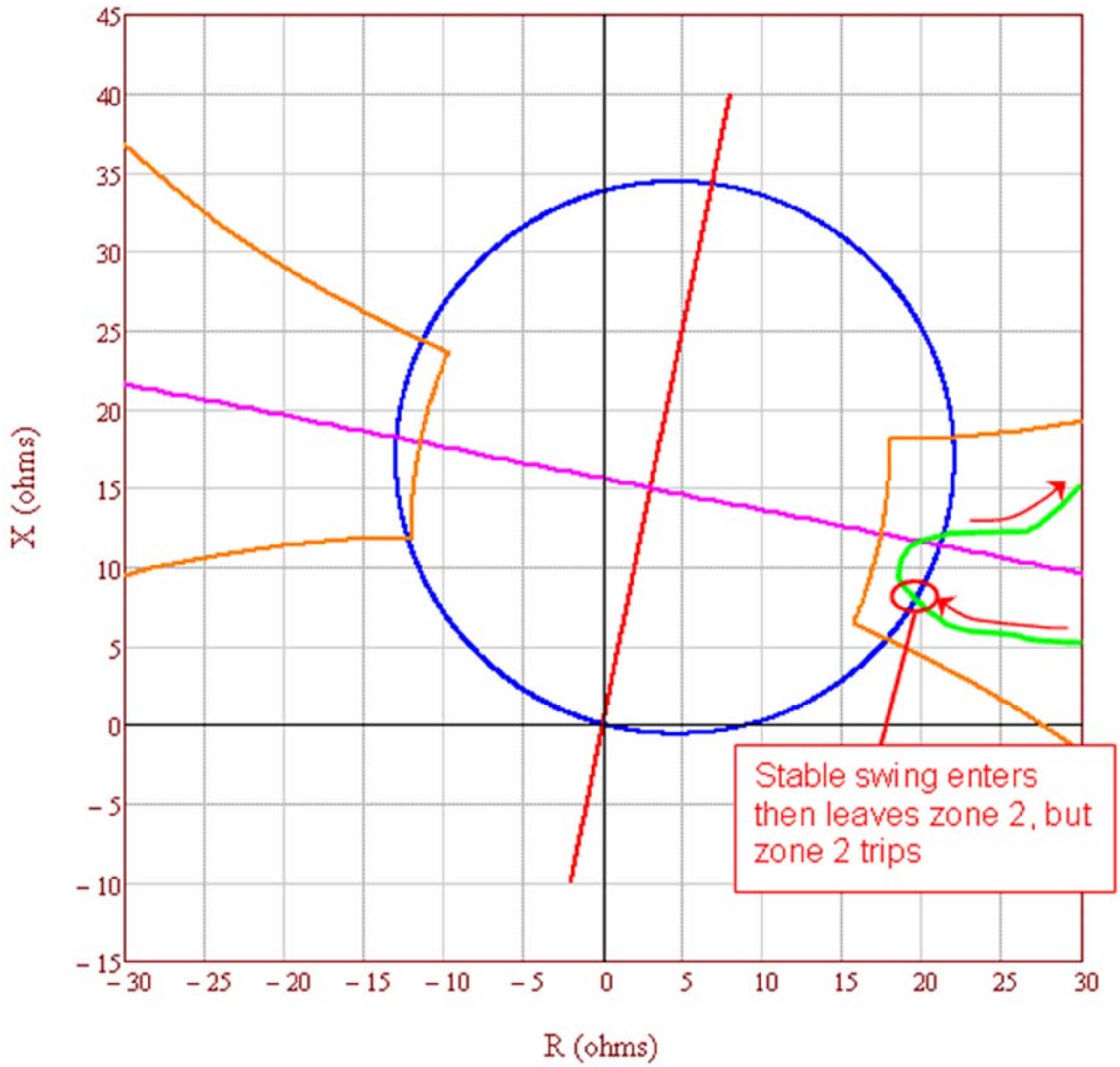

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

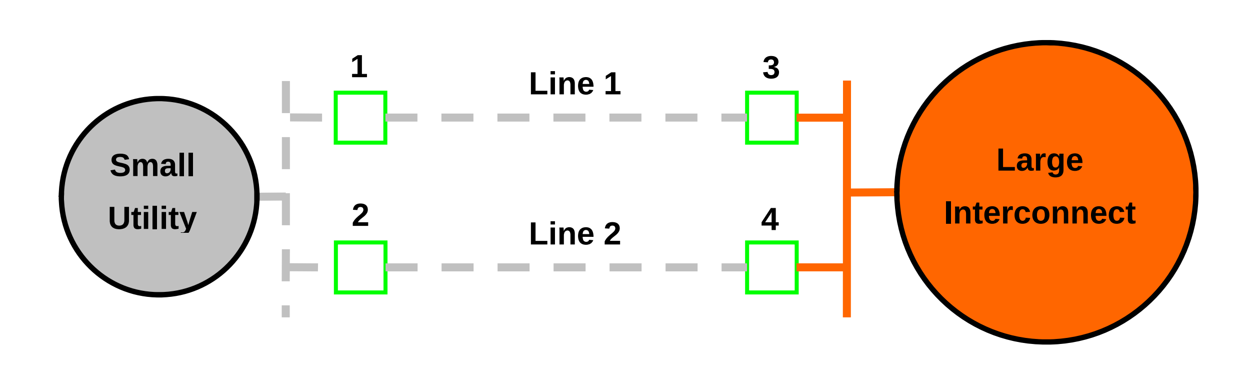

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2~~1~~**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1** Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.
     - **4.1.2** Planning Coordinator.
     - **4.1.3** Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.
   - **4.2. Facilities:** The following Elements that are part of the Bulk Electric System (BES):
     - **4.2.1** Generators.
     - **4.2.2** Transformers.
     - **4.2.3** Transmission lines.
5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. ~~An~~ Elements associated with ~~that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an~~ angular instability identified in Planning Assessments~~constraint~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

~~[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.~~

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

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[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element’s load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity’s Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity’s Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity’s Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity’s Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1)

$$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

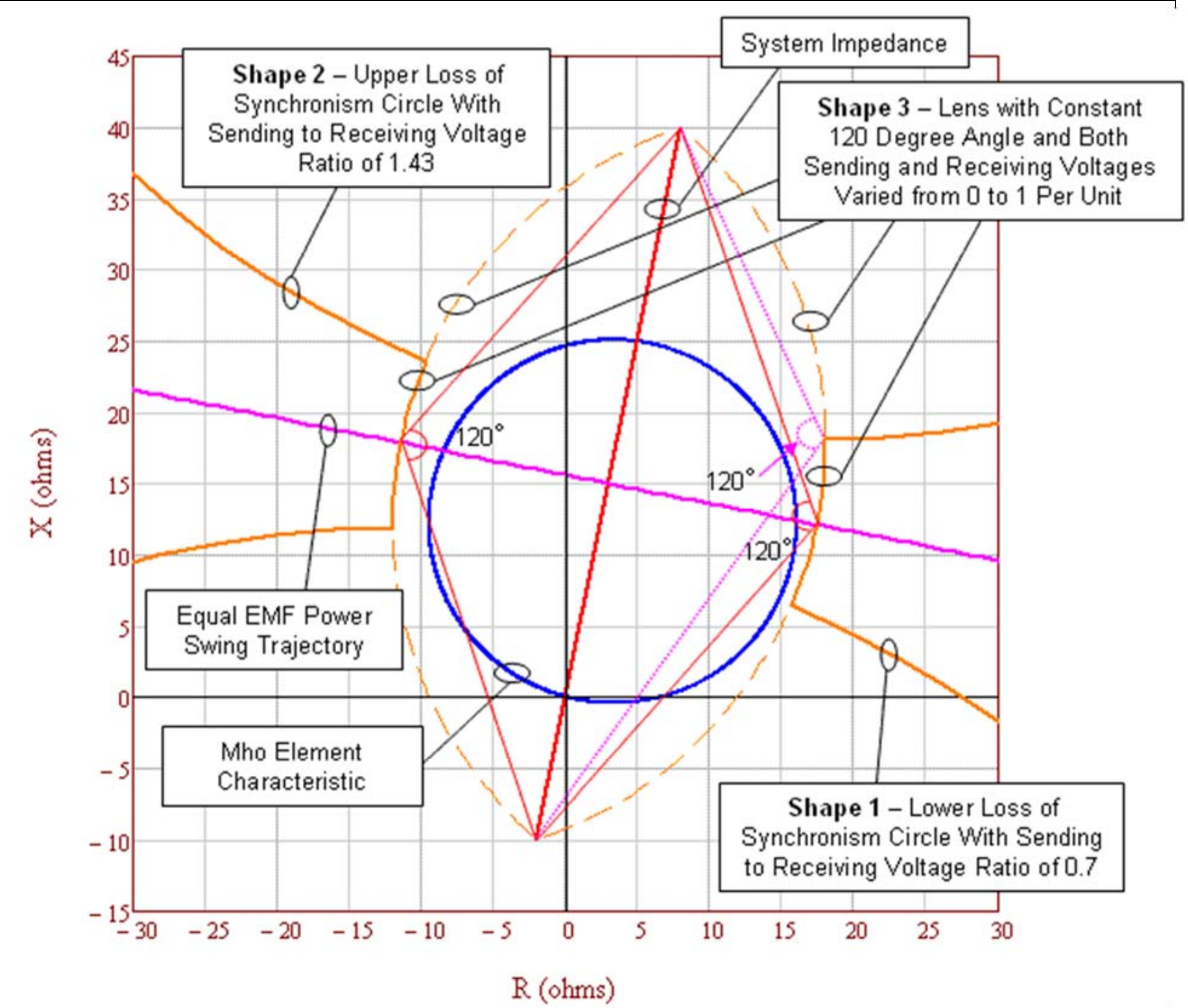


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

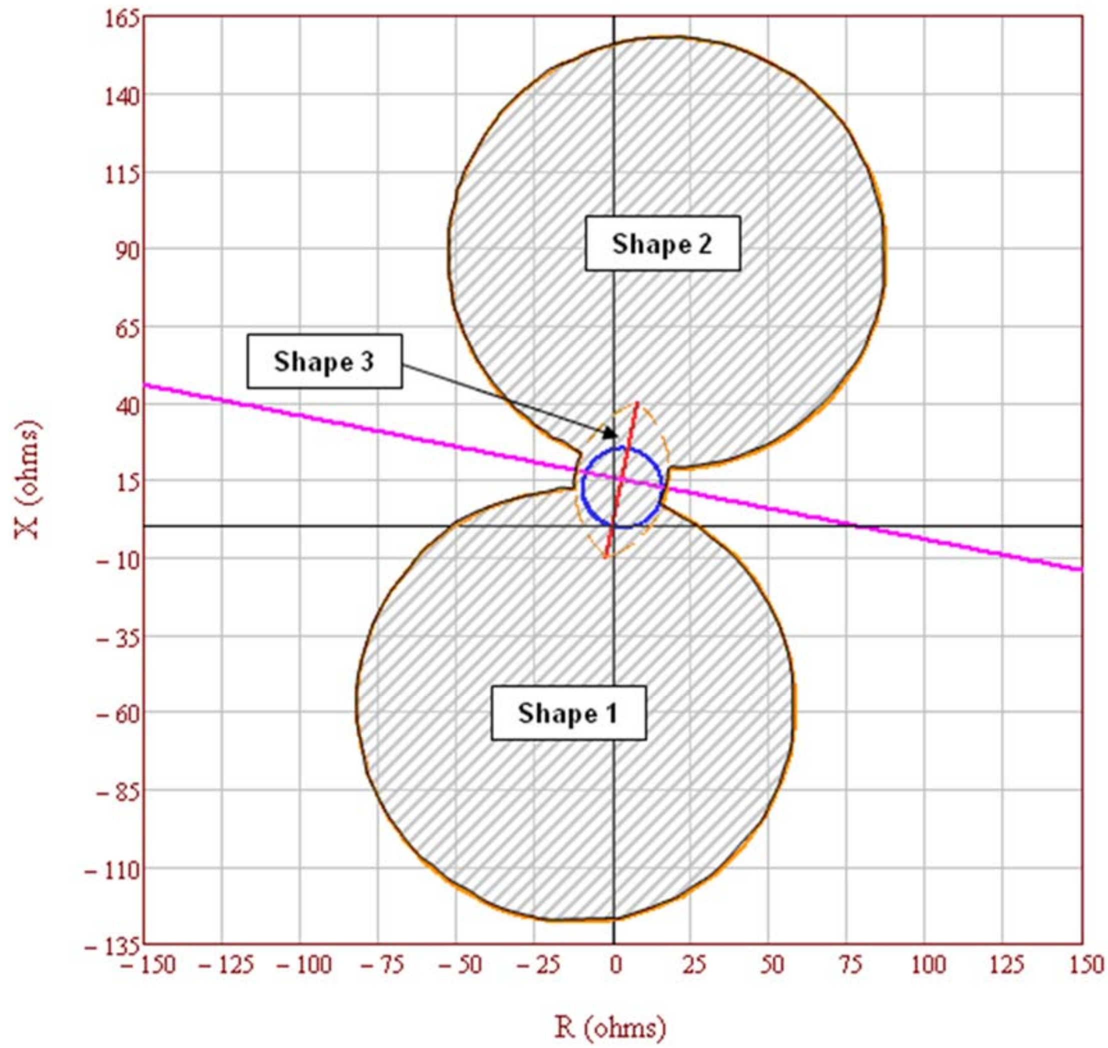


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

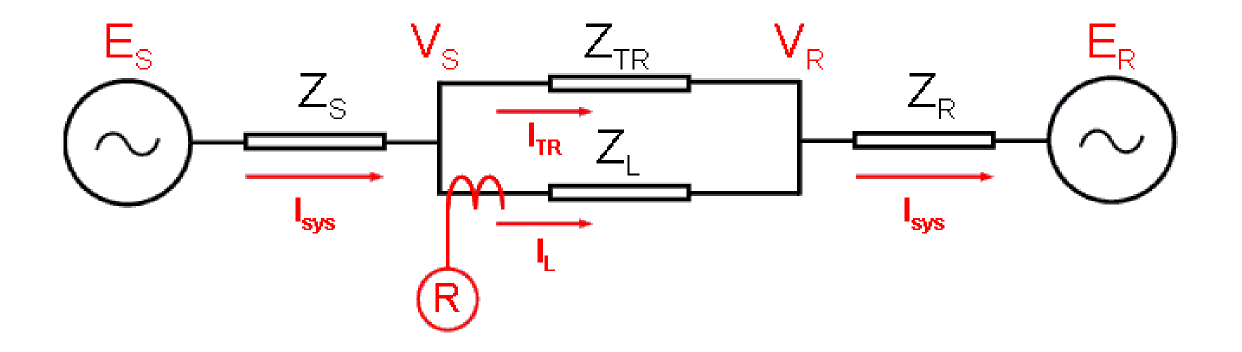


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

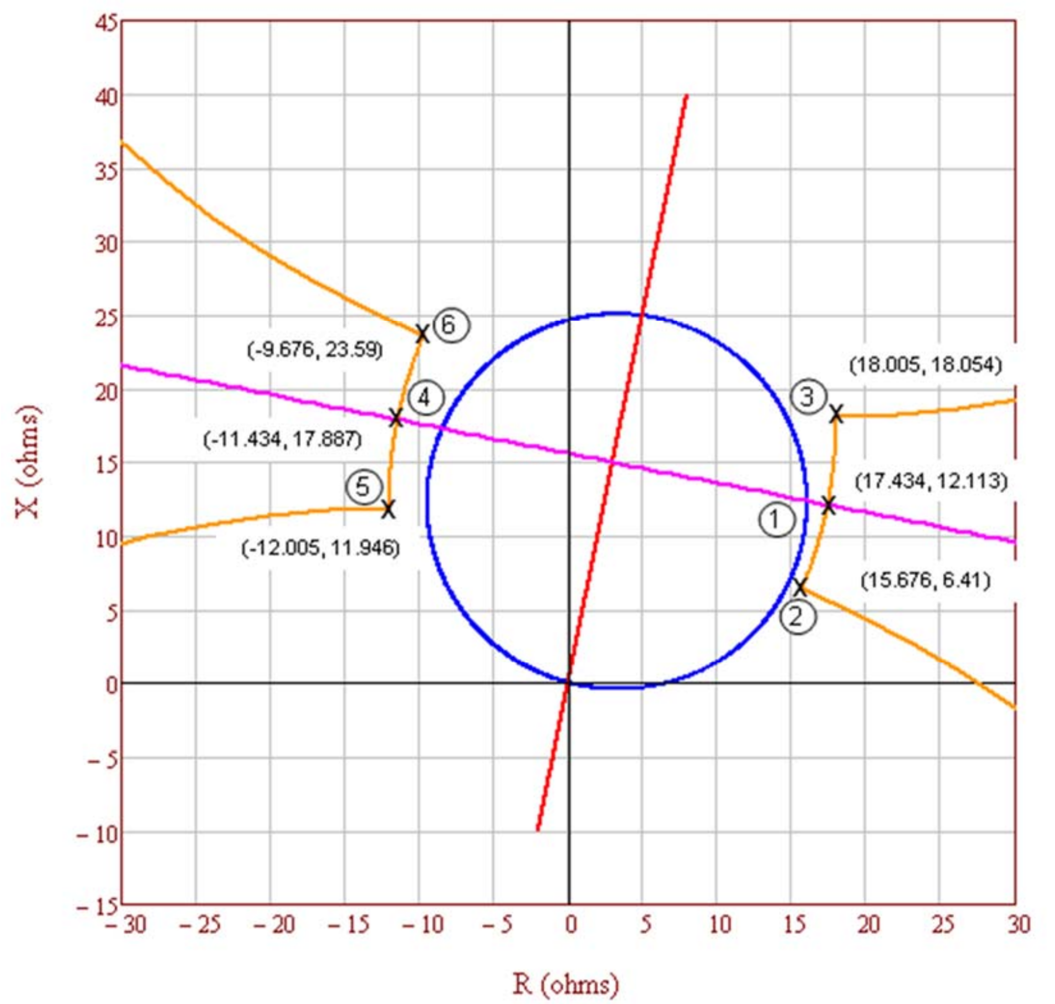


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4+j20)\times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10+j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2+j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\big((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\big)}{\big((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\big)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\big((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\big)}{\big((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\big)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

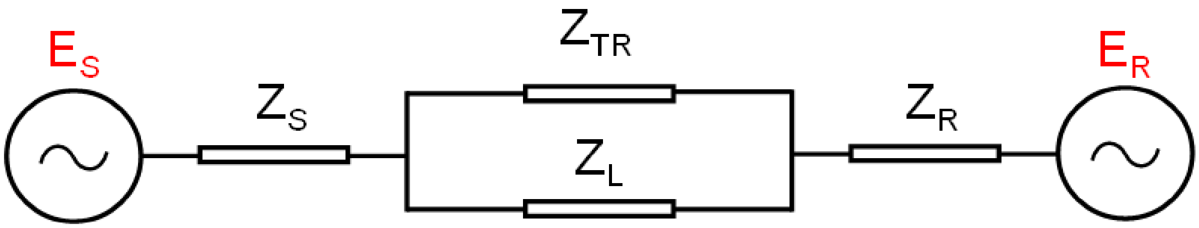
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}511\angle 131.1°\ A]$
	$V_S = 95{,}756\angle - 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}756\angle - 106.1°\ V}{4{,}511\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

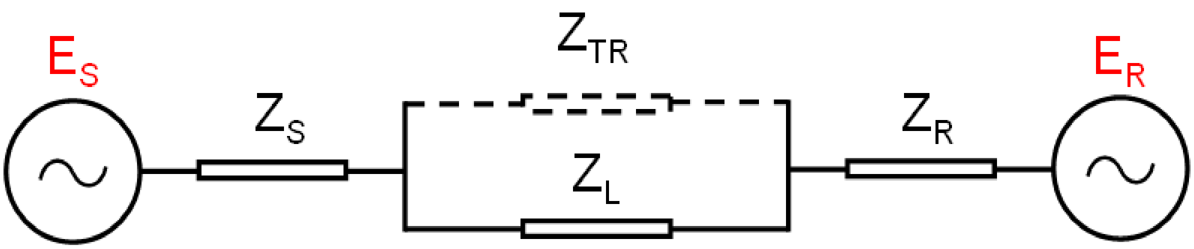
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1^\circ\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1^\circ\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240^\circ\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1^\circ\ A]$
	$V_S = 98{,}265\angle - 110.6^\circ\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6^\circ\ V}{3{,}854\angle 137.1^\circ\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

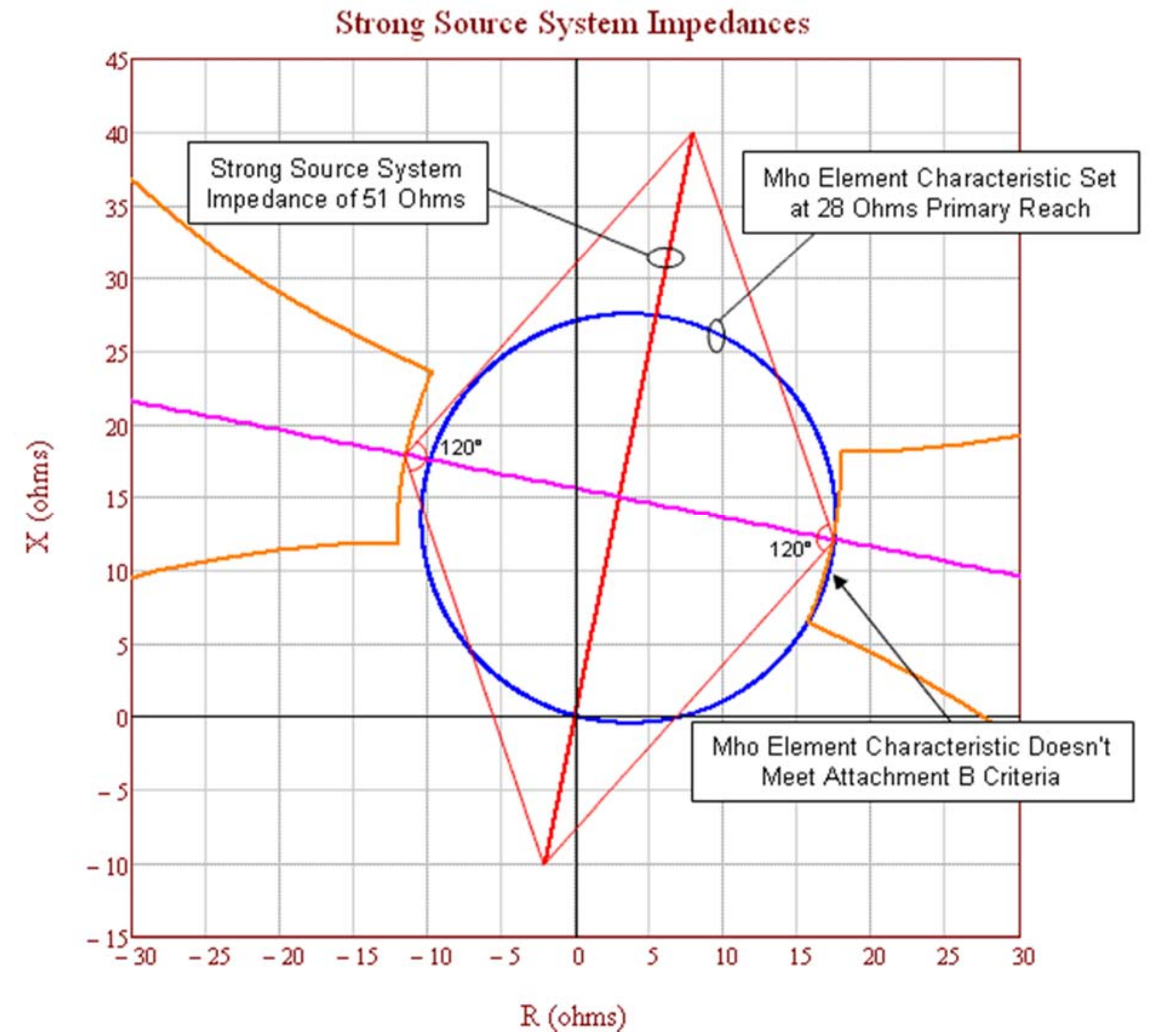


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

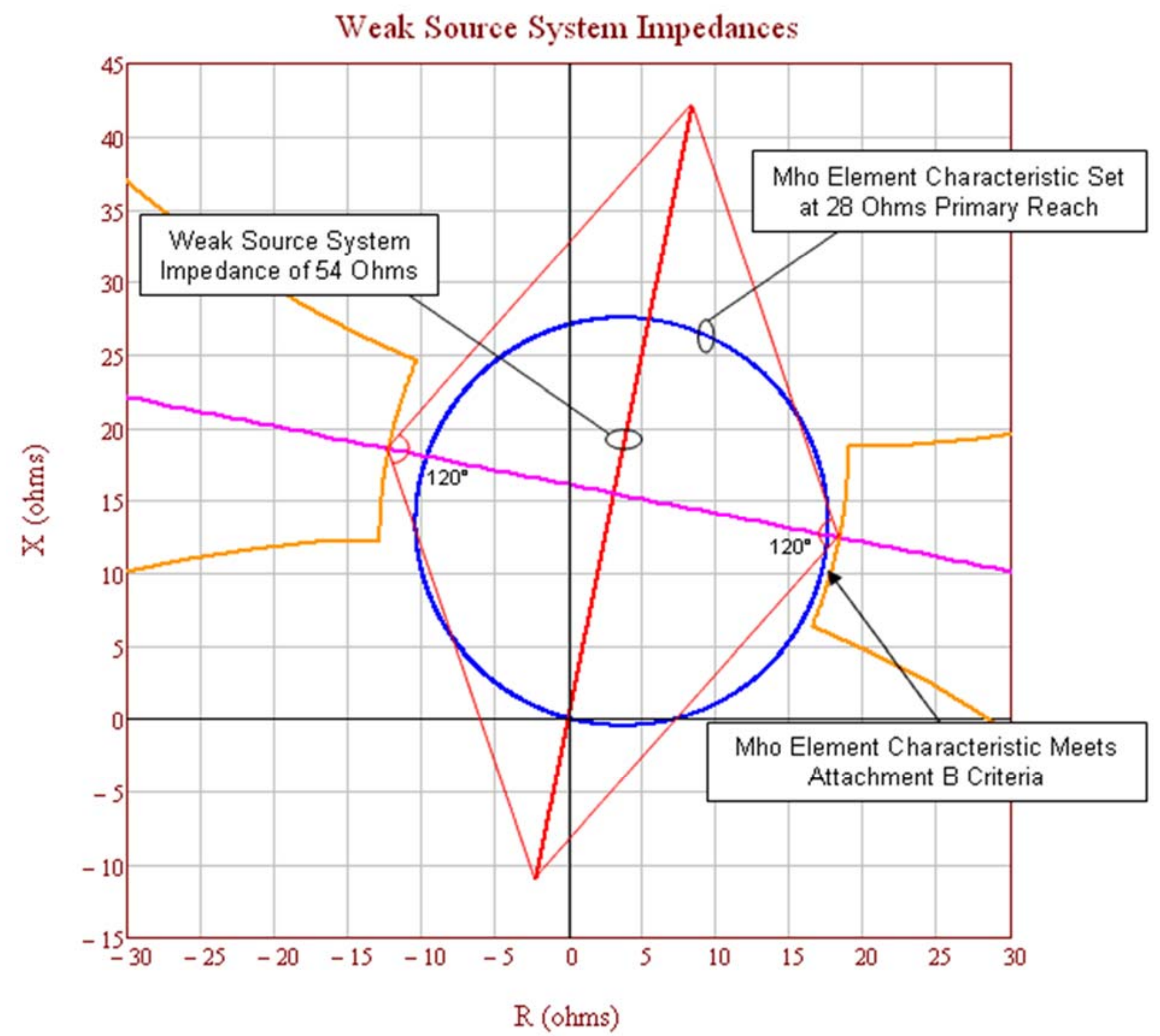


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

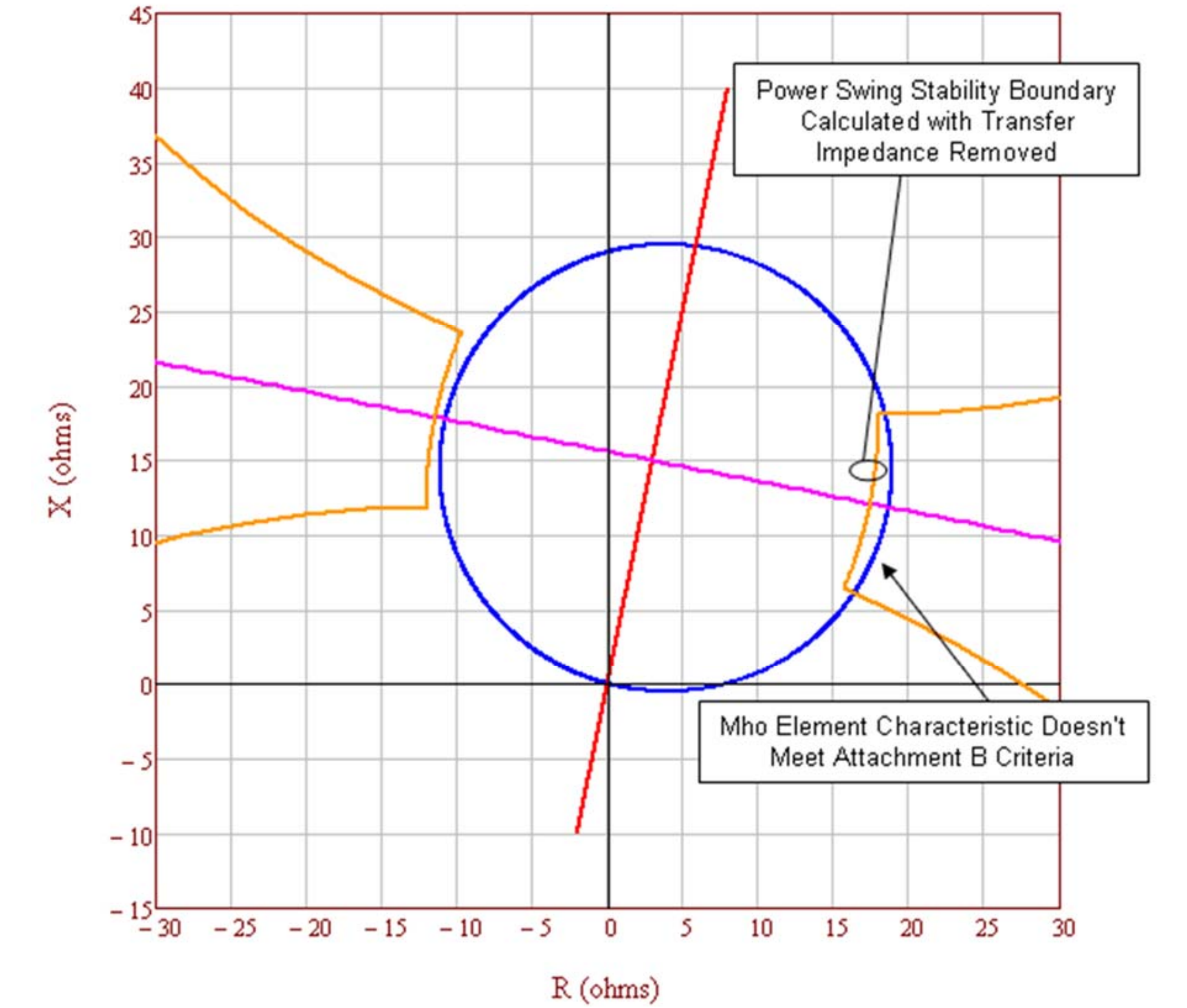


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\,V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\,V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\, V - [(2 + j10\, \Omega) \times 4{,}511\angle 71.3°\, A]$
	$V_S = 95{,}757\angle 106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\, V}{4{,}511\angle 71.3°\, A}$
	$Z_{L-Relay} = 17.434 + j12.113\, \Omega$

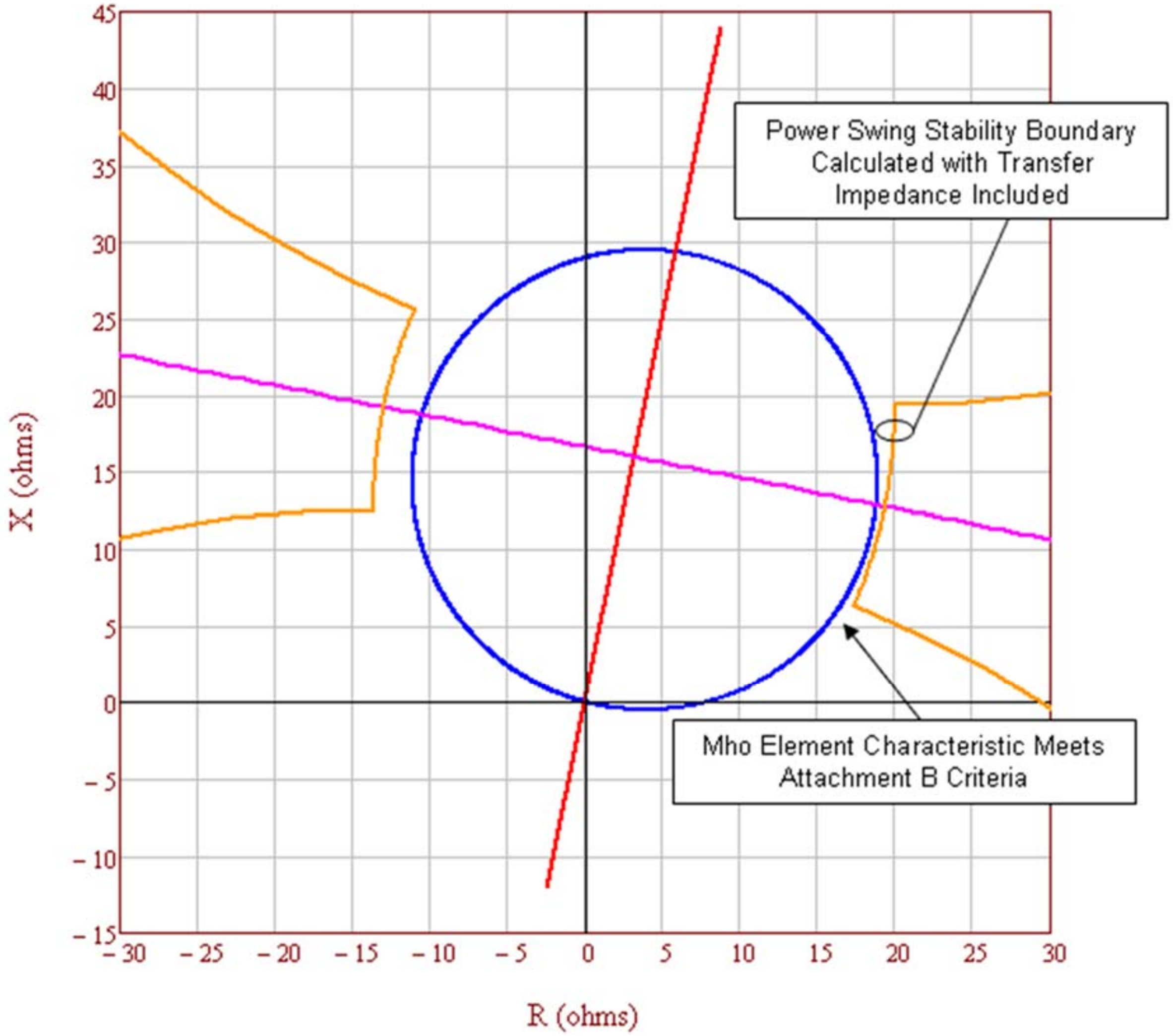


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on ZL (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on ZL (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on ZL.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

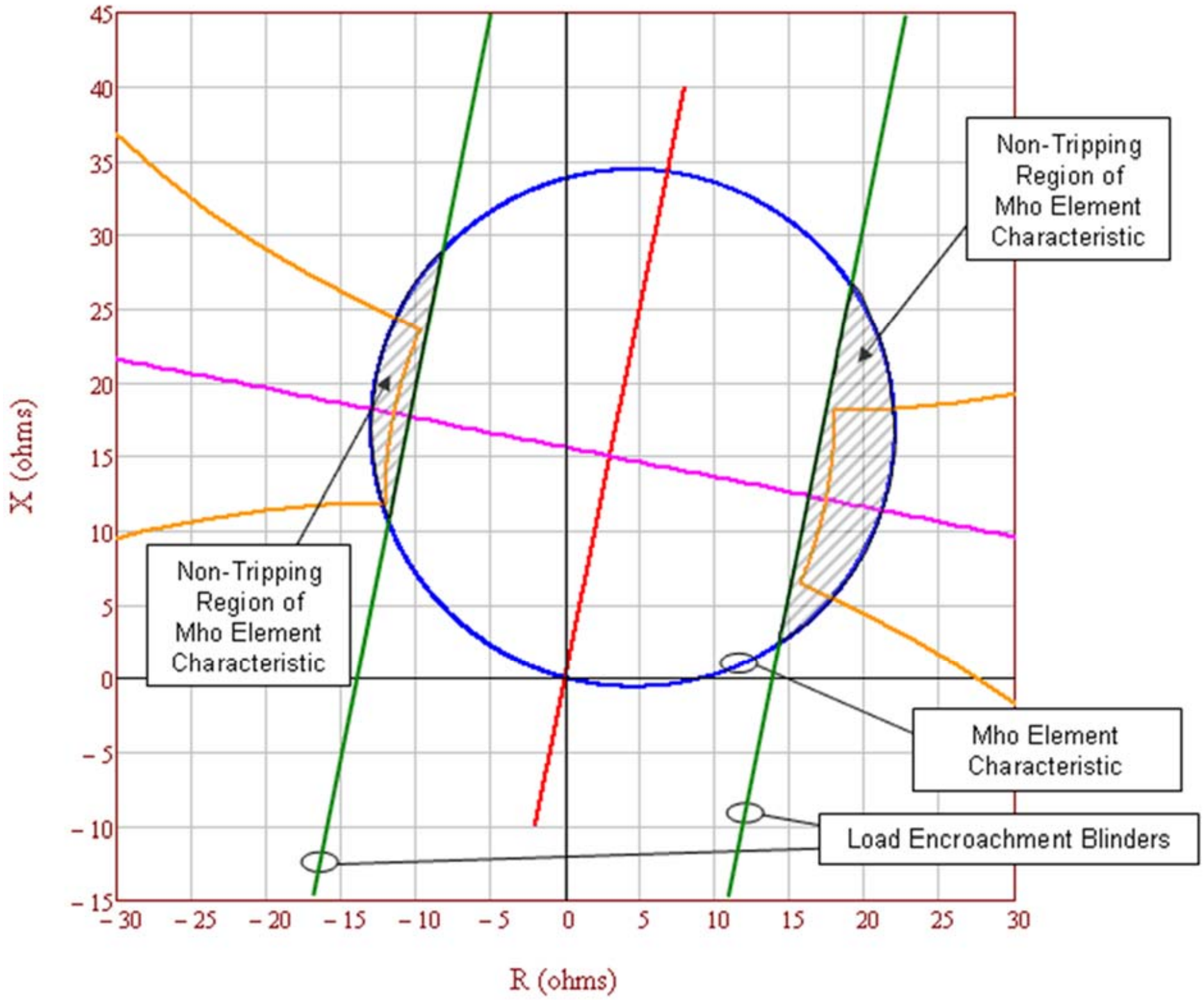


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

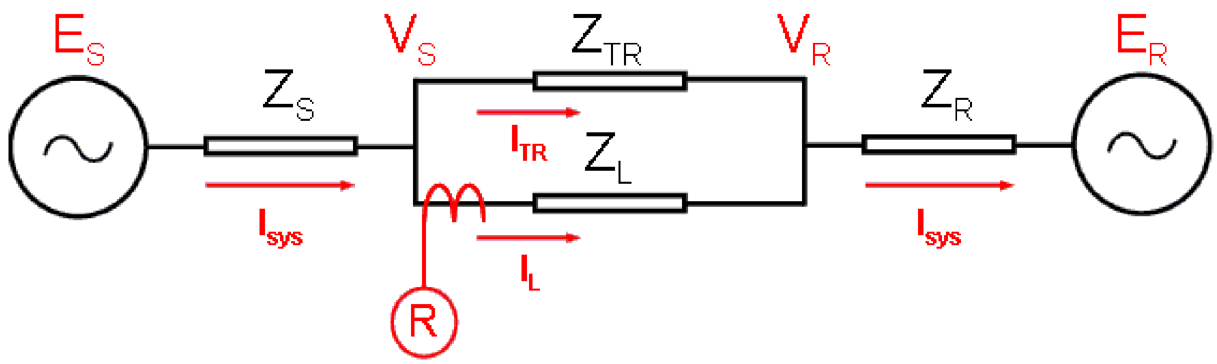


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

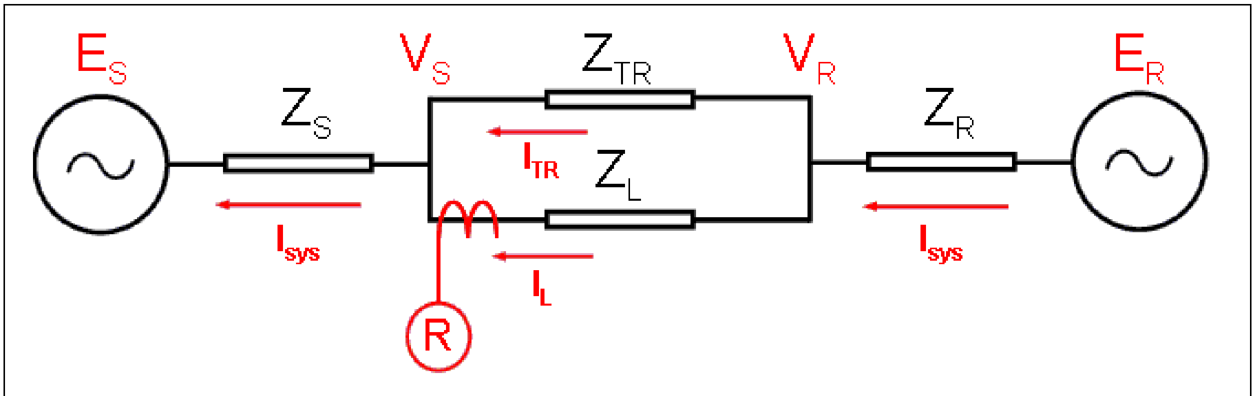


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

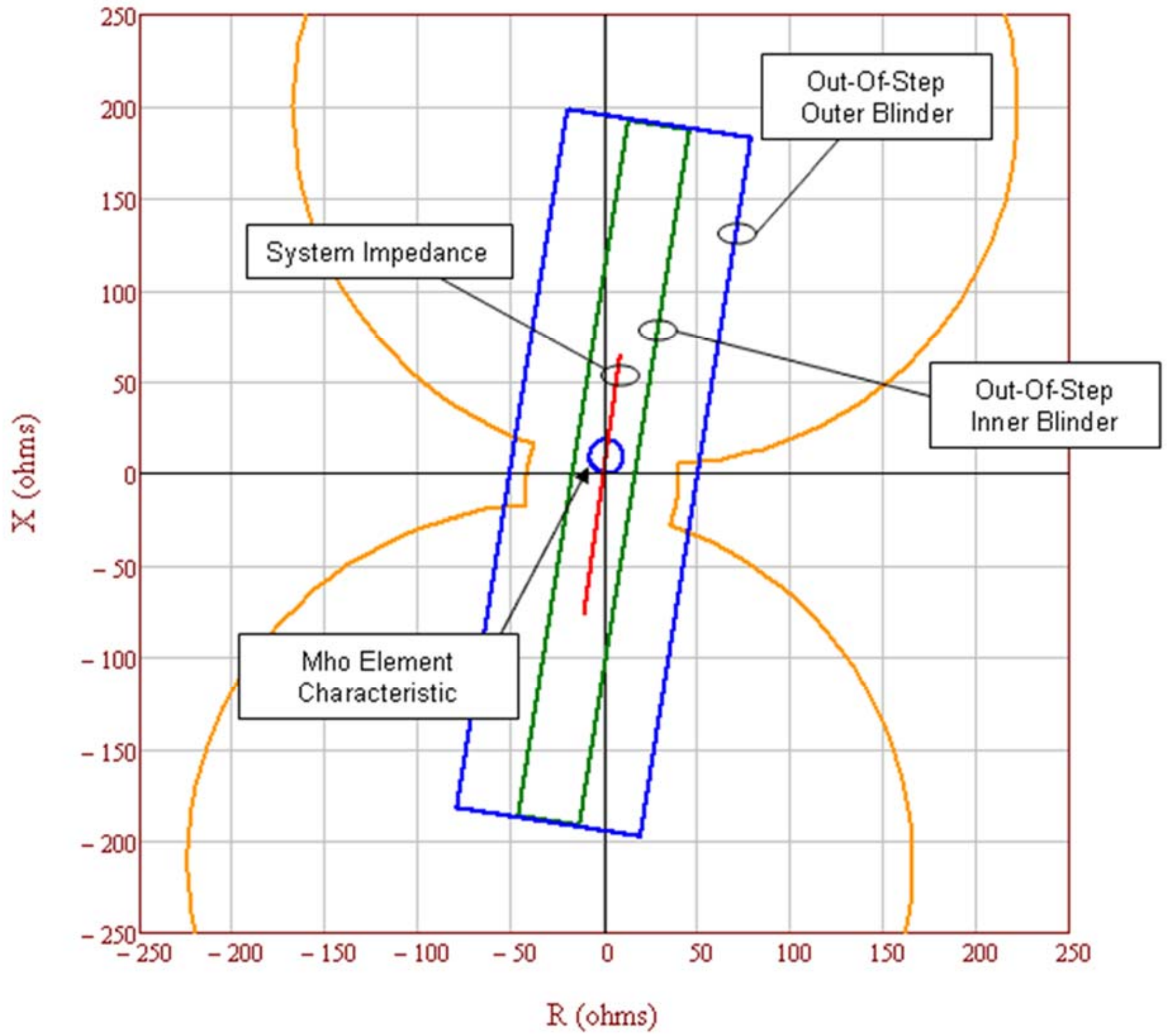


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}} \right) \right] + \left[\frac{Z_{sys}}{N^2 - 1} \right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega} \right) \right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1} \right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

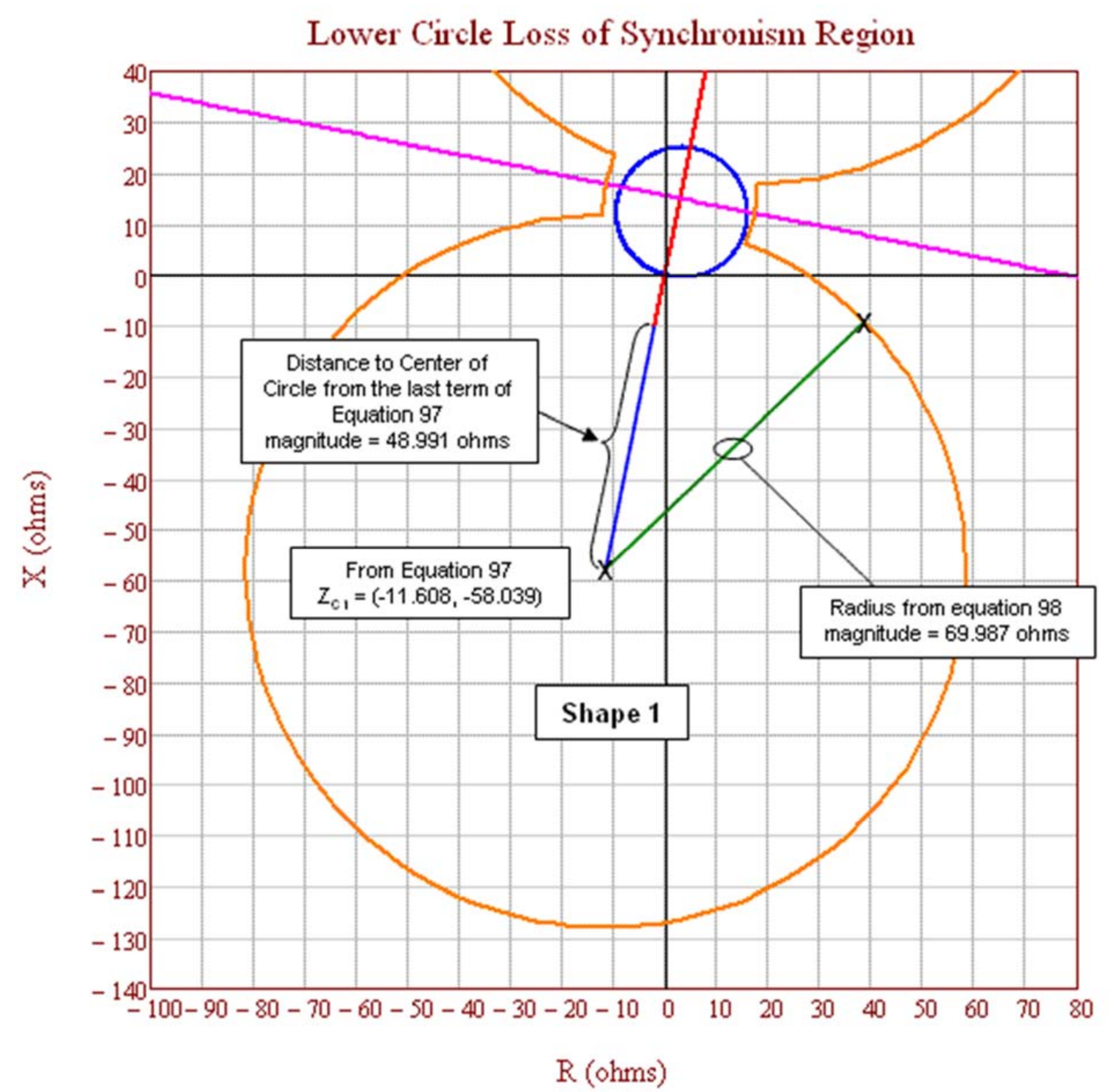


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

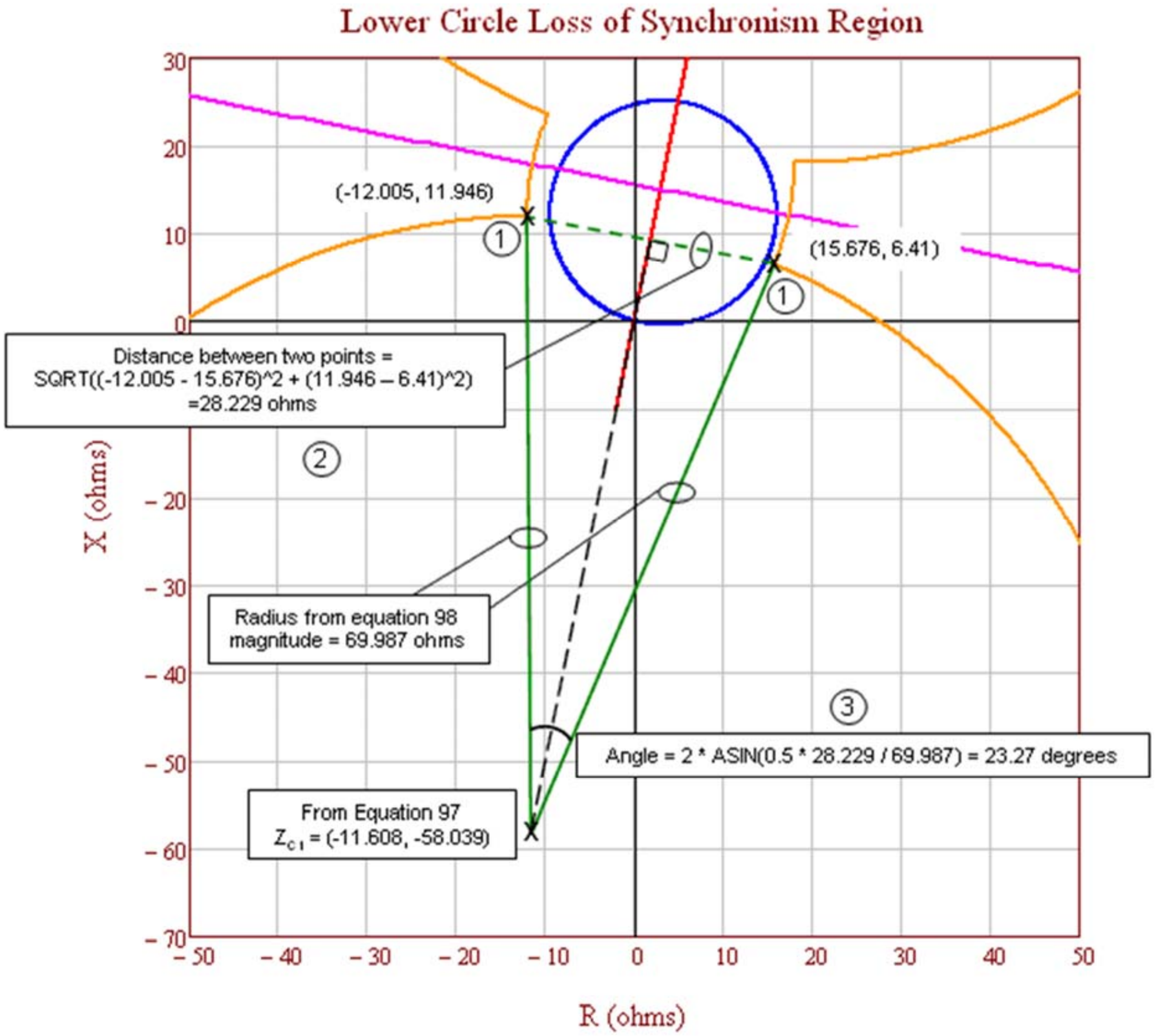


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

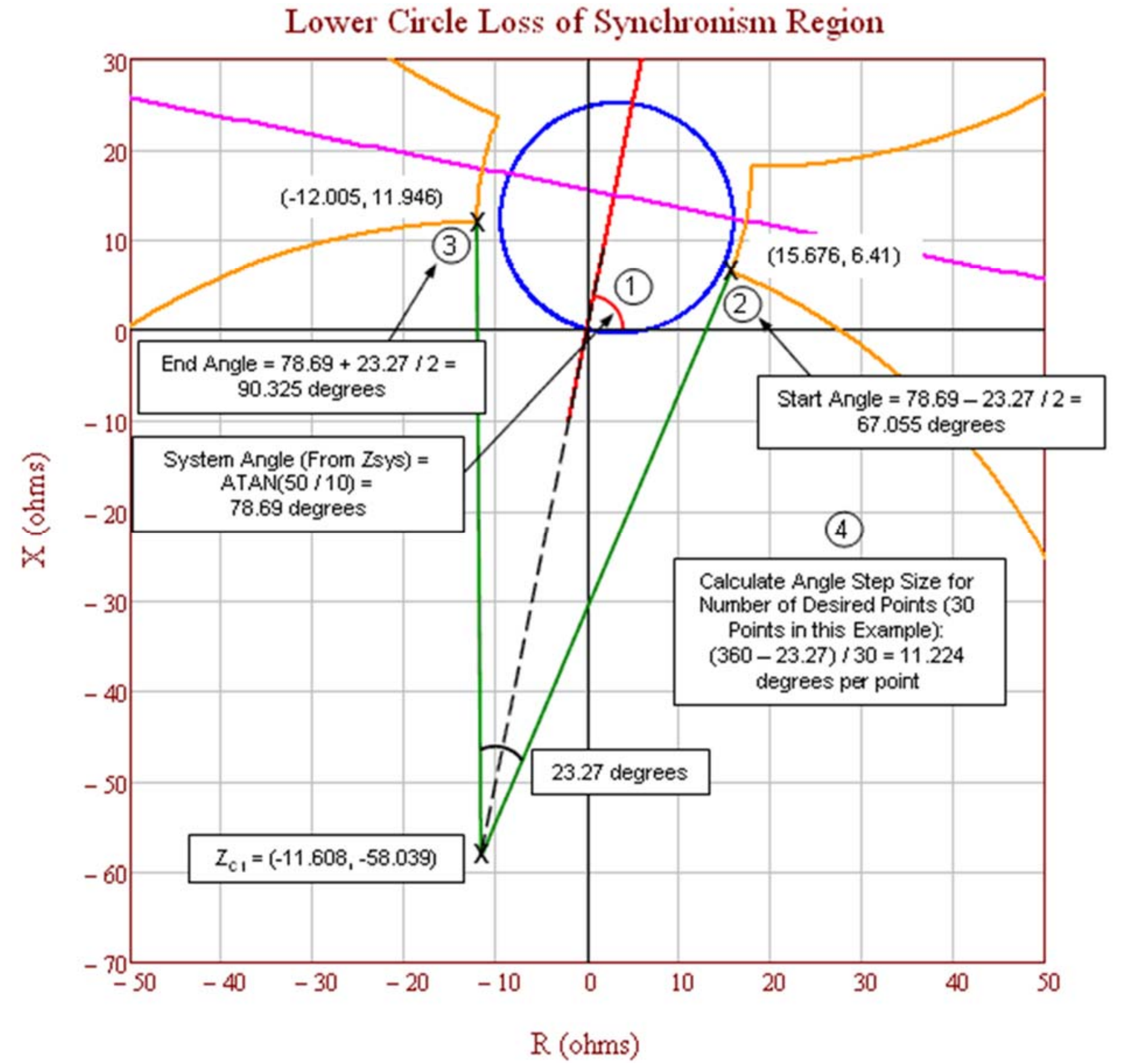


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

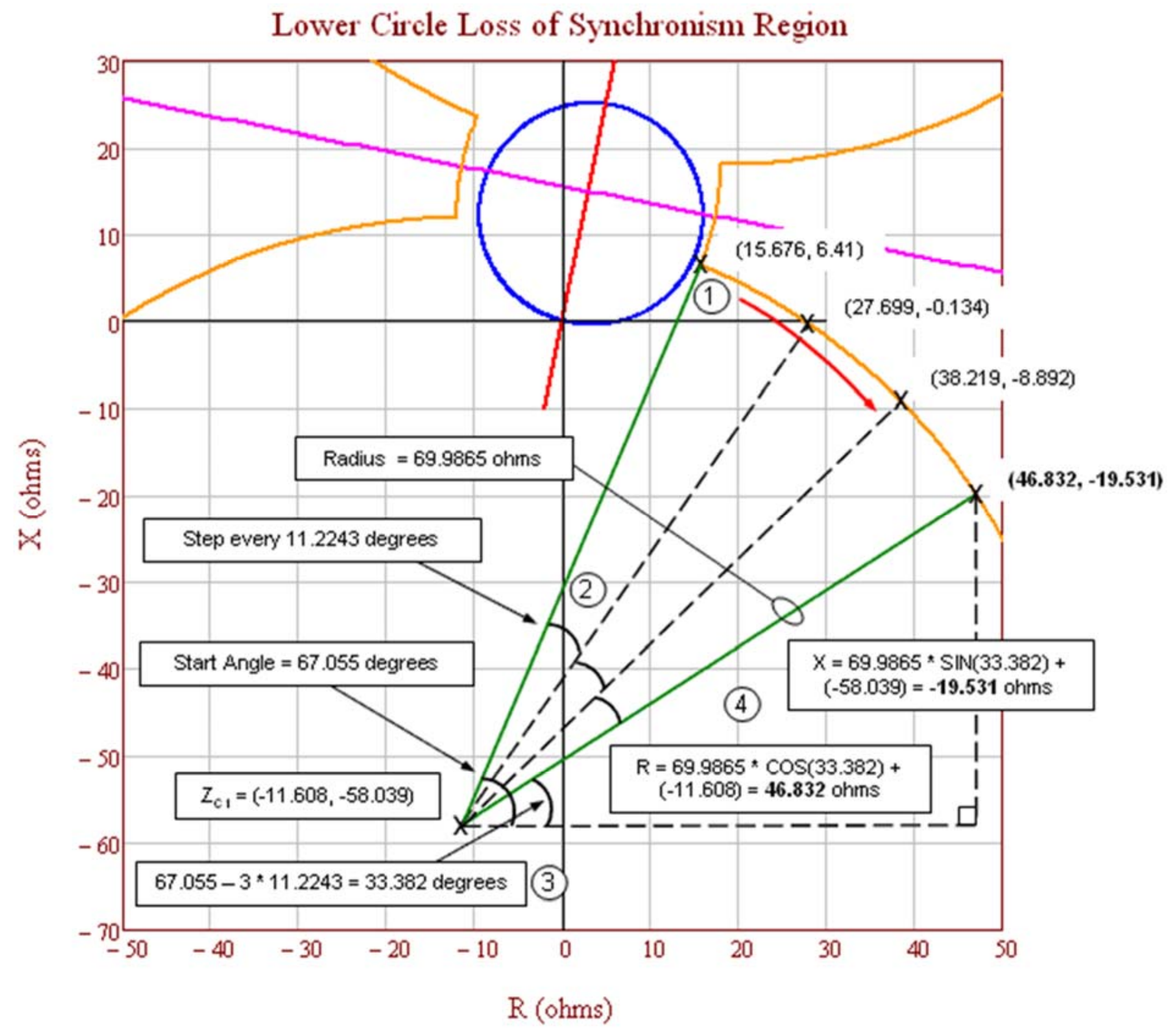


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

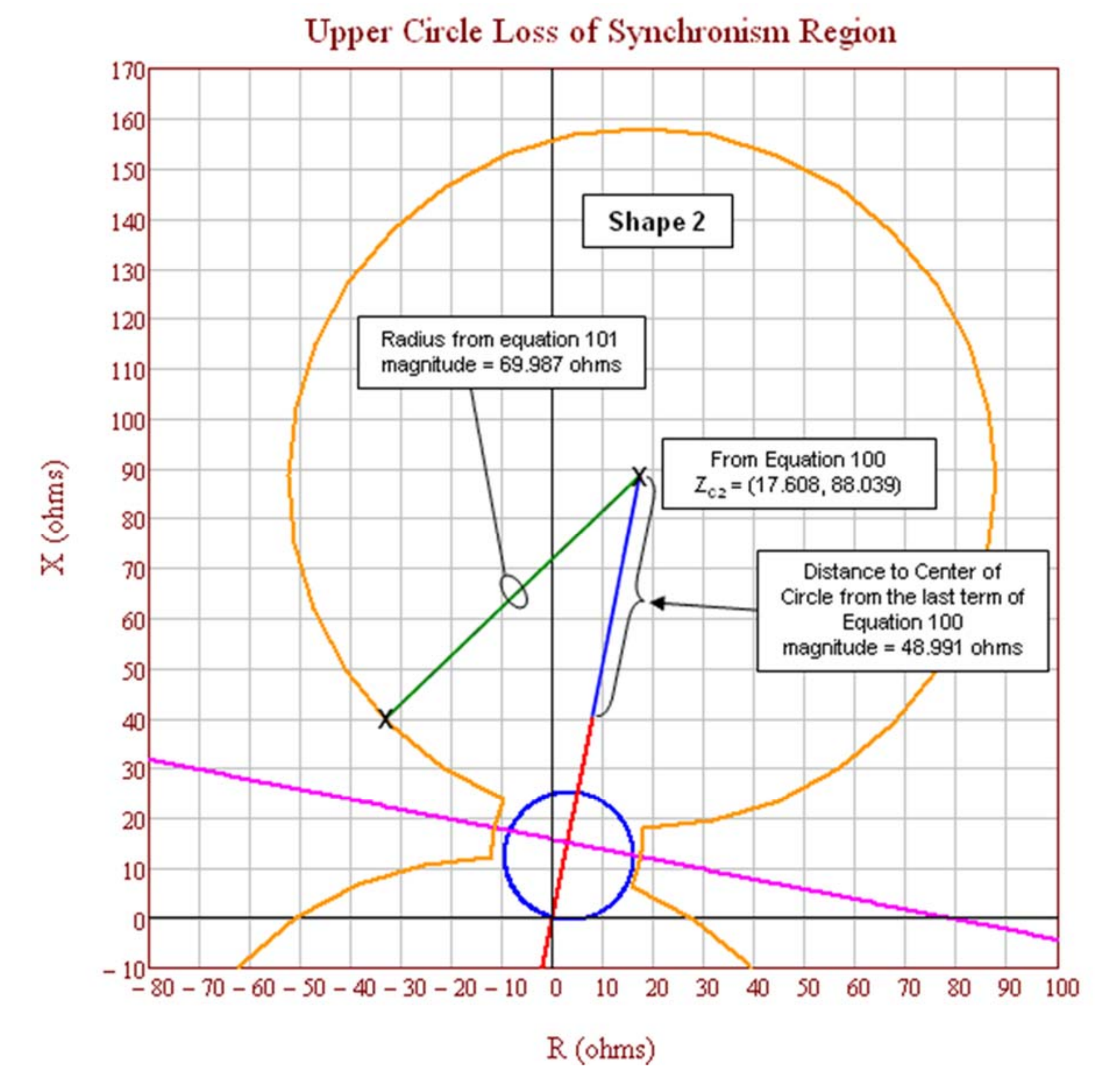


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

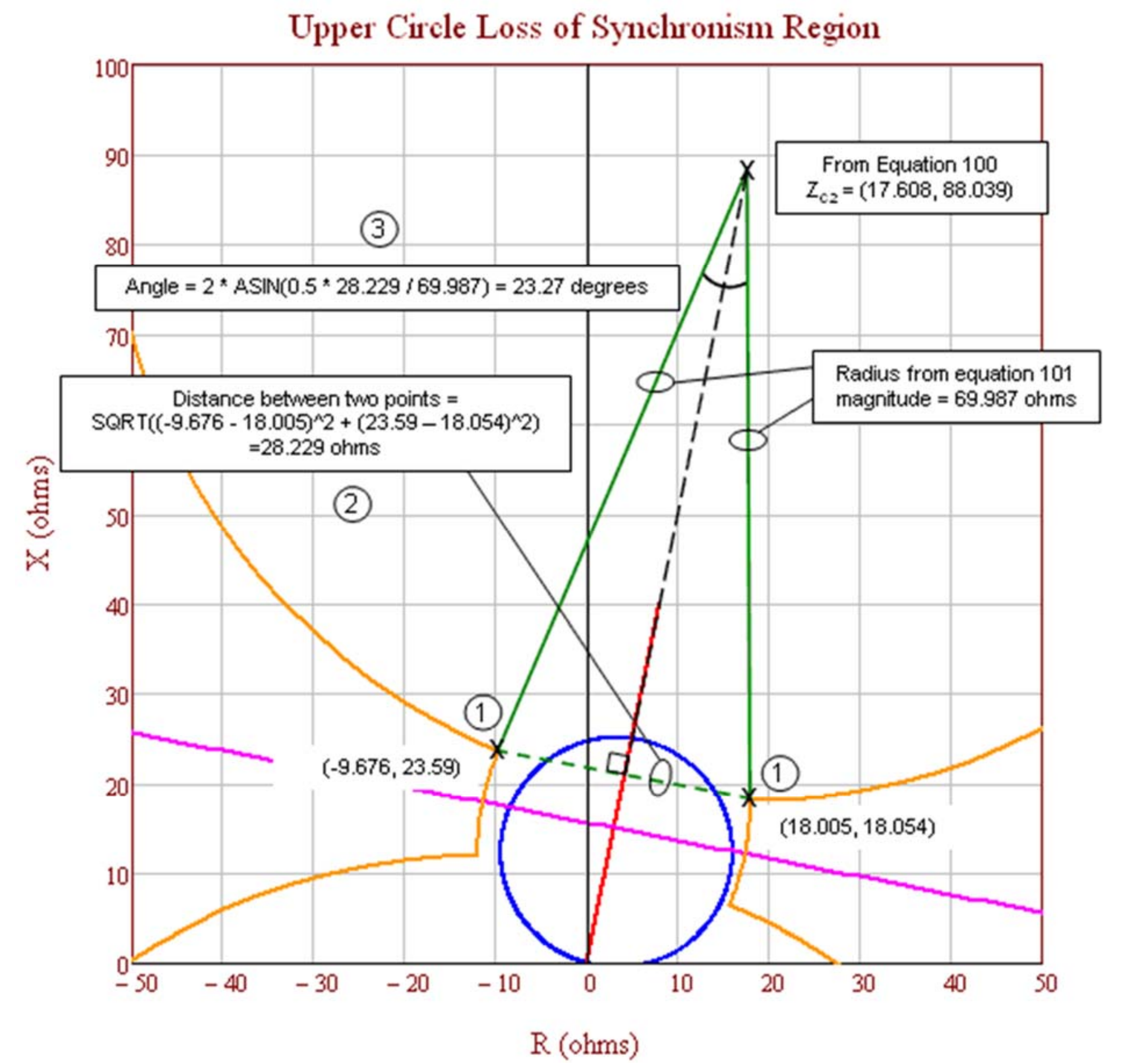


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

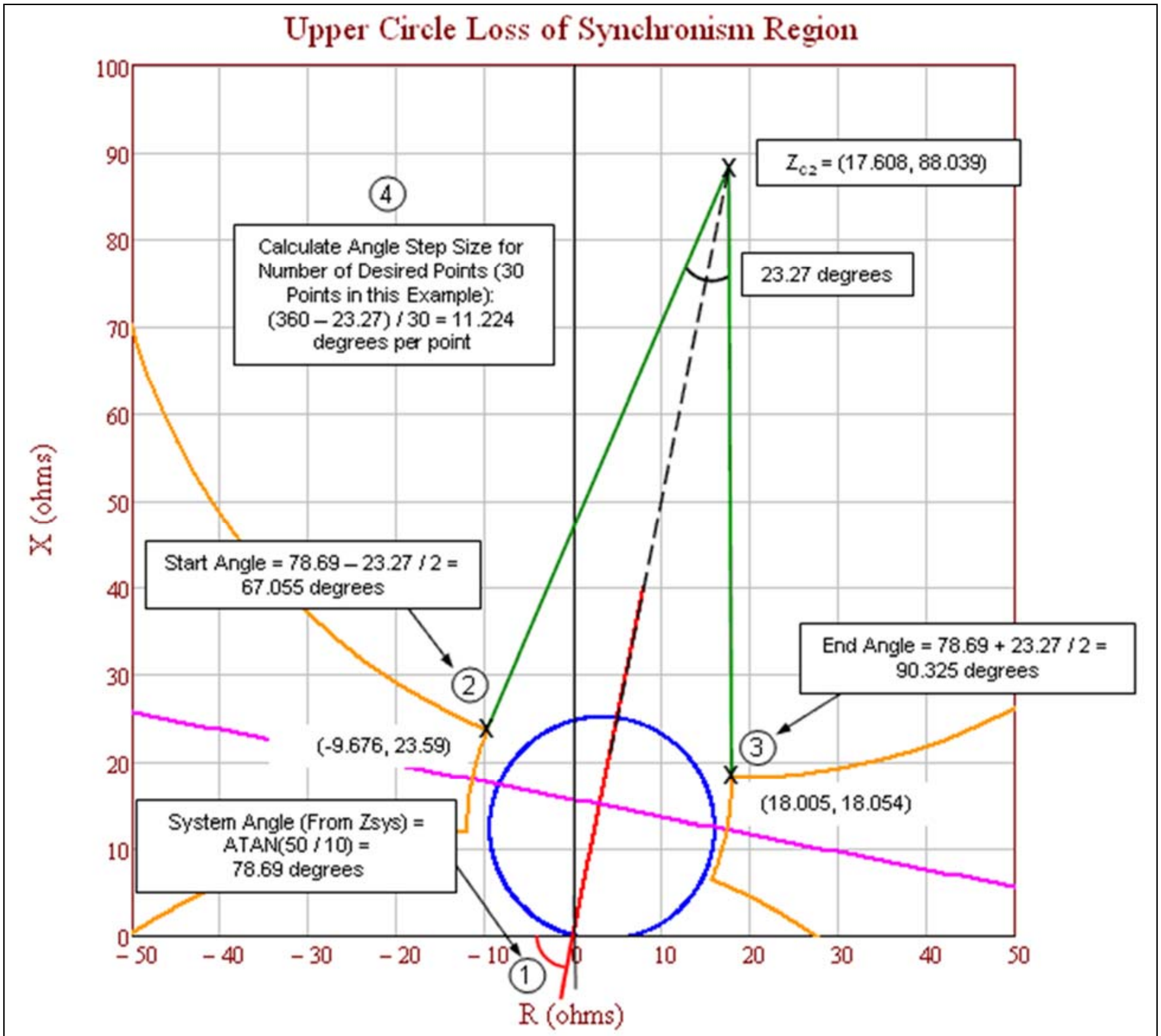


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

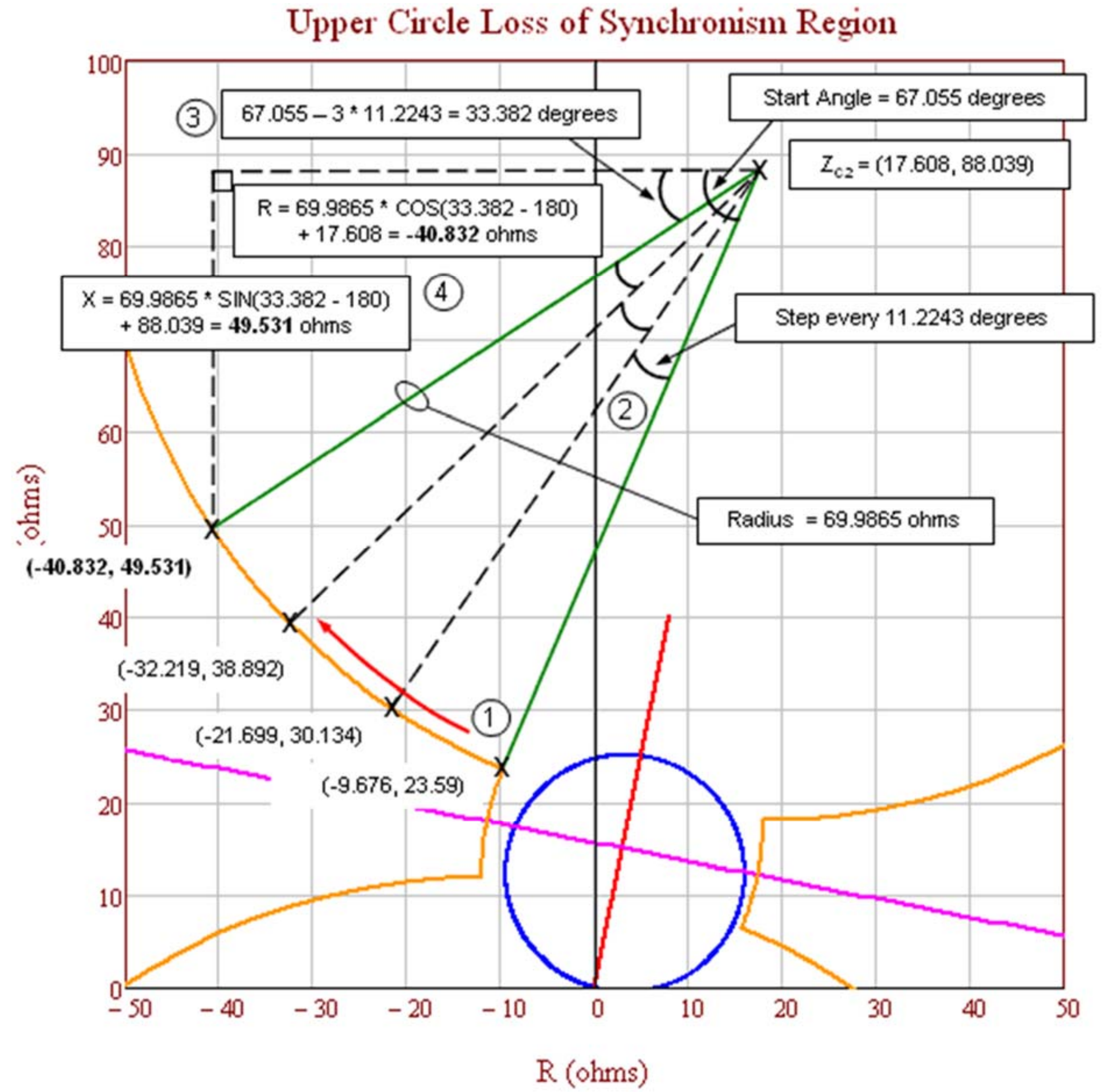


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\,V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\,V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\,V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\,V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\,\Omega$	$Z_L = 1.3 + j8.7\,\Omega$	$Z_R = 0.3 + j7.3\,\Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\,\Omega + (1.3 + j8.7)\,\Omega + (0.3 + j7.3)\,\Omega$		
	$Z_{sys} = 4.6 + j42\,\Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\,V - 139{,}430\angle 0°\,V)}{(4.6 + j42)\,\Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\,A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

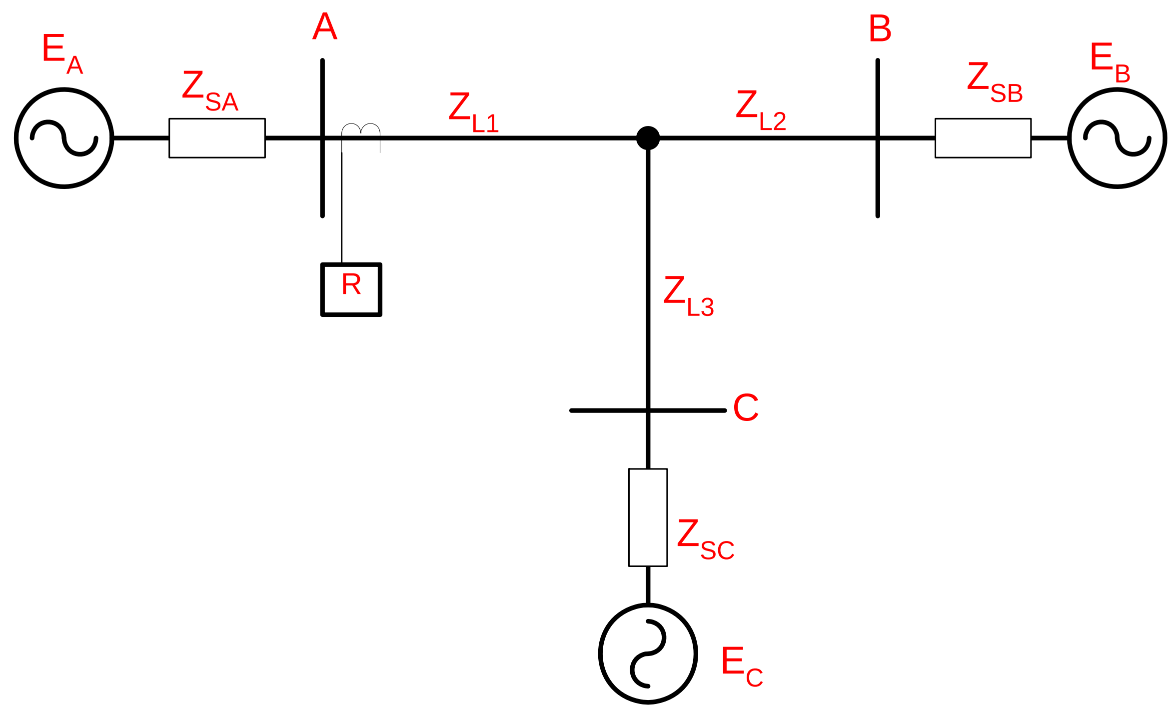


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

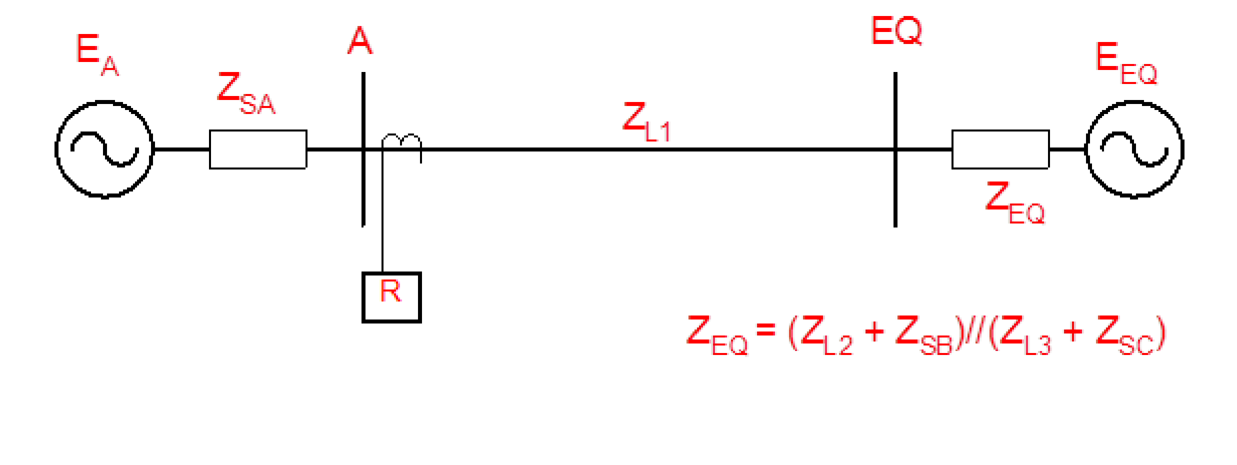


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

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[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

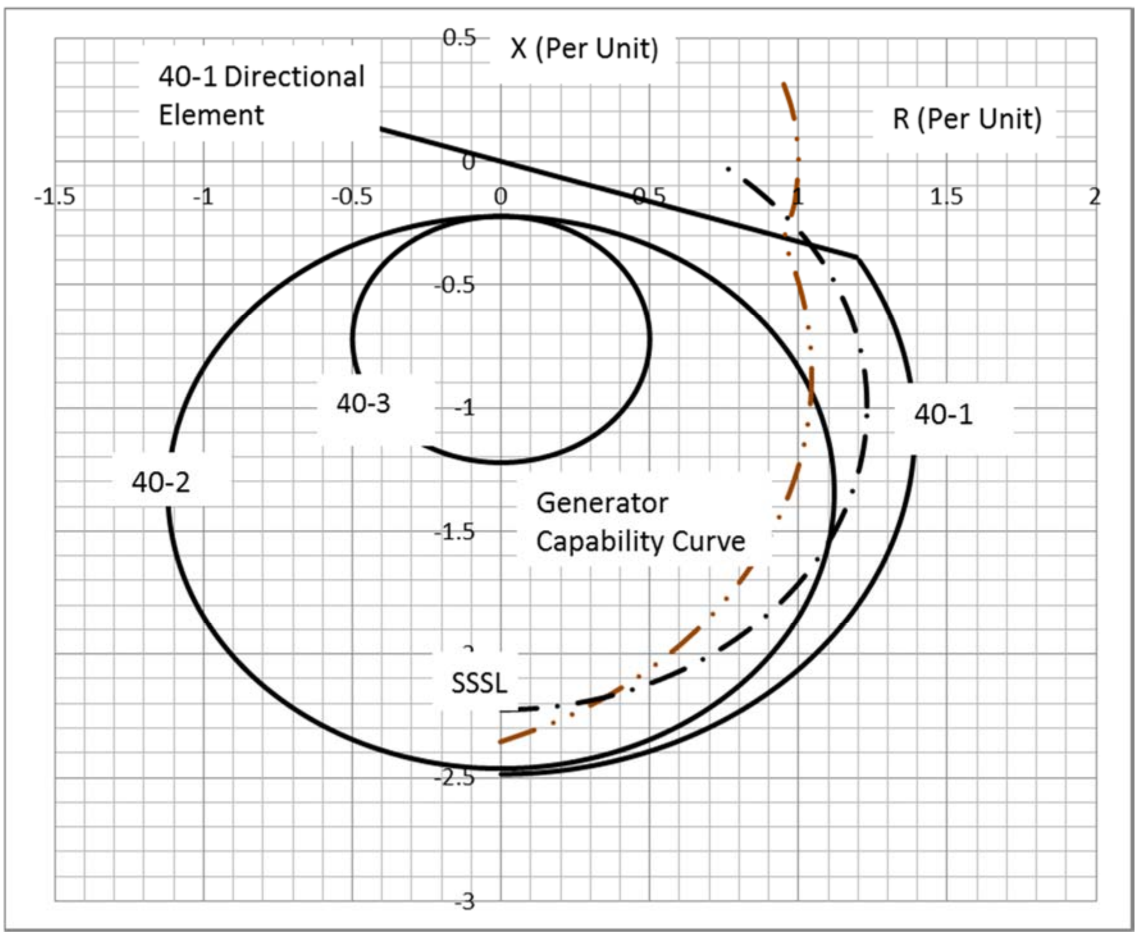

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

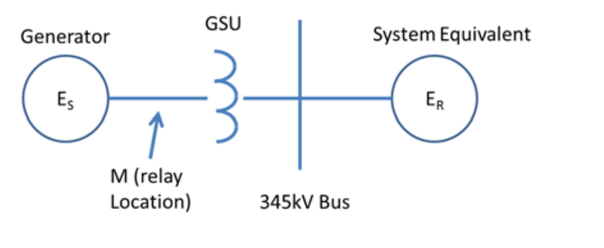

Figure 17: Simple one-line diagram of the system to be evaluated.

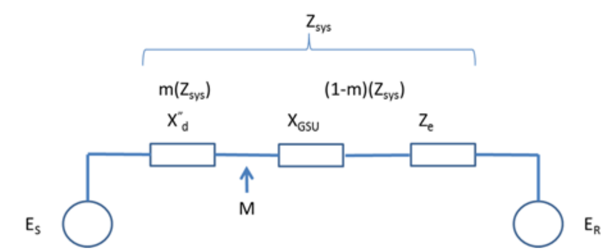

Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	20 kV
Generator step-up (GSU) transformer rating	880 MVA
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[29] Ibid, Kimbark.

Table15: Example Data (Generator)		
50	I (pickup) = 5.0 per unit	
Transmission Owned Load-Responsive Protective Relays		
21-2	Diameter = 0.55 per unit	
	MTA = 85°	

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta)+(m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta)+(m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°)+(0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

Angle (δ) (Degrees)	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

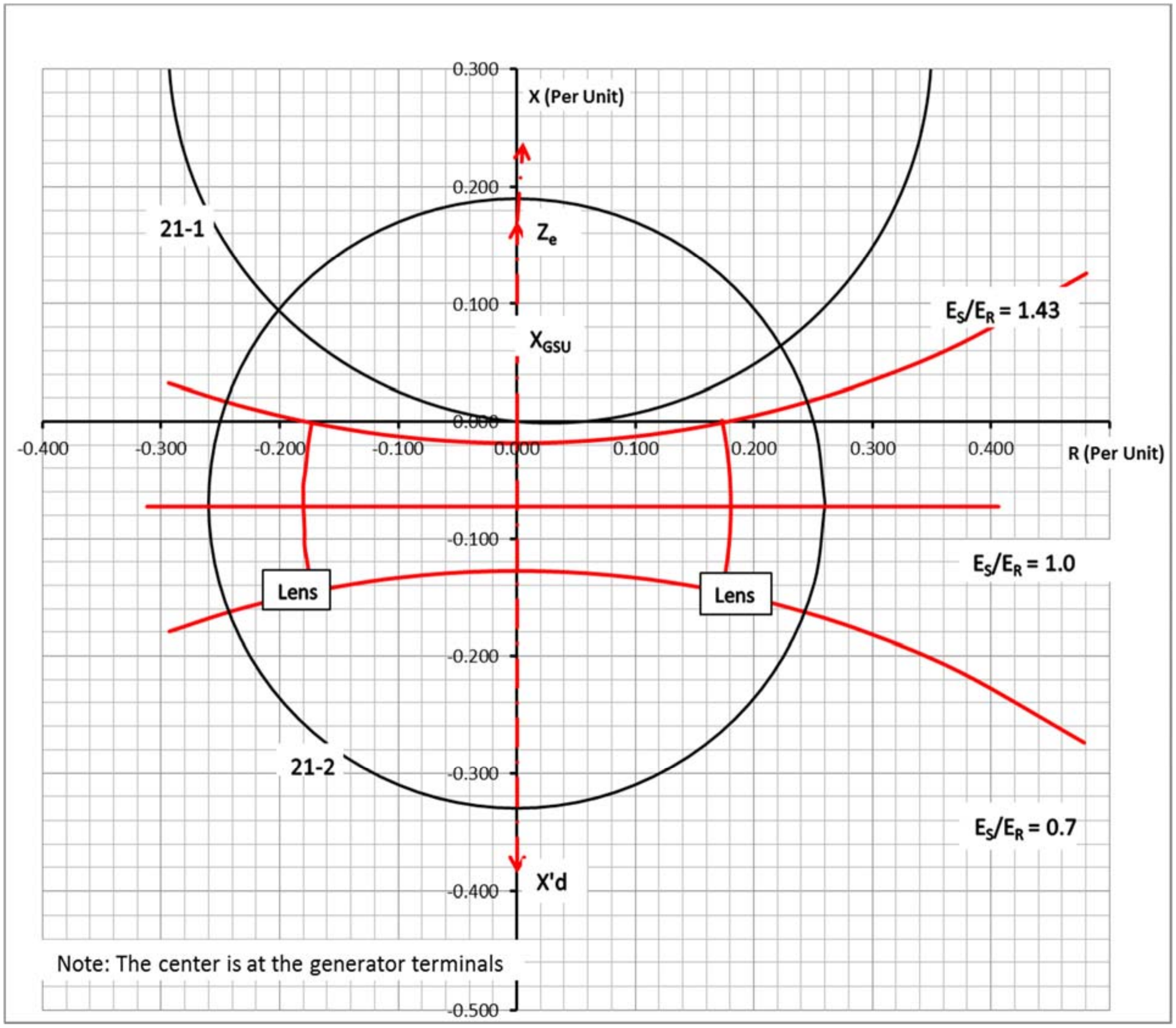

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

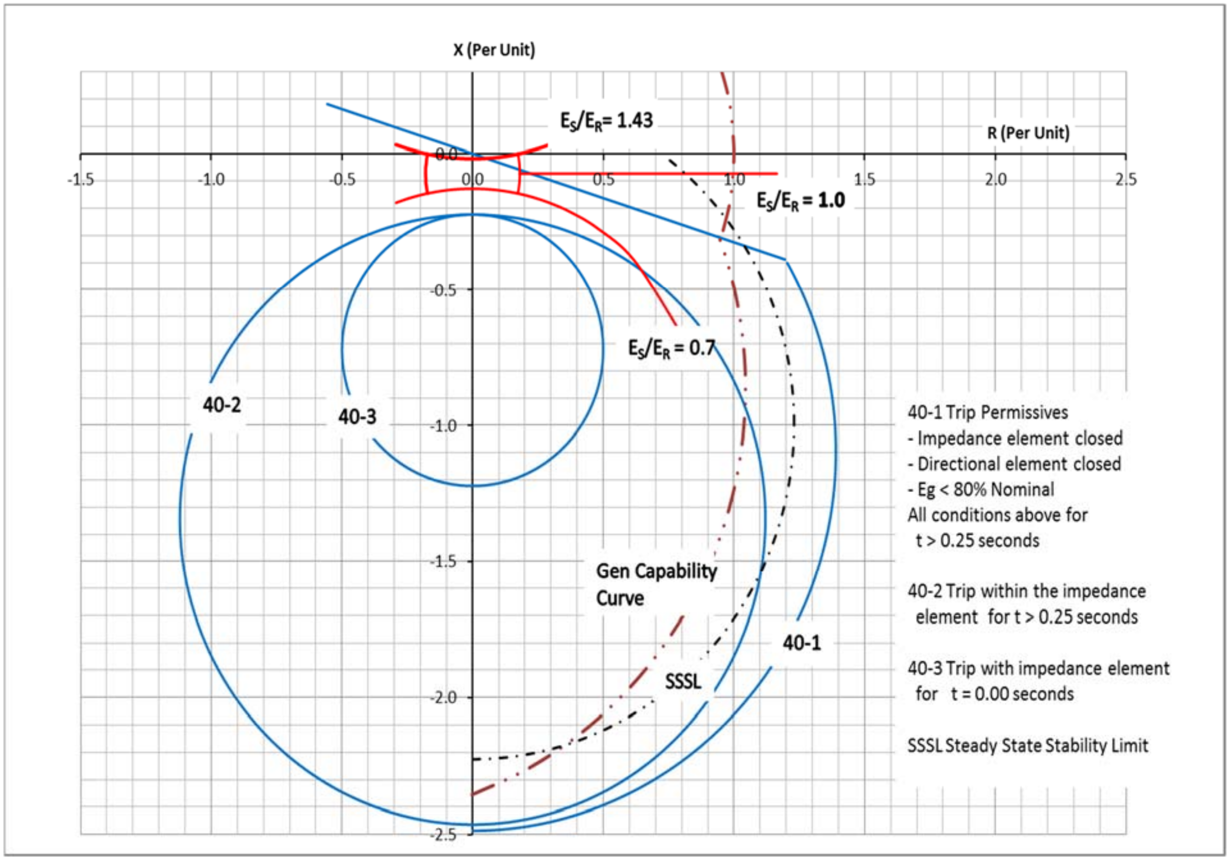

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

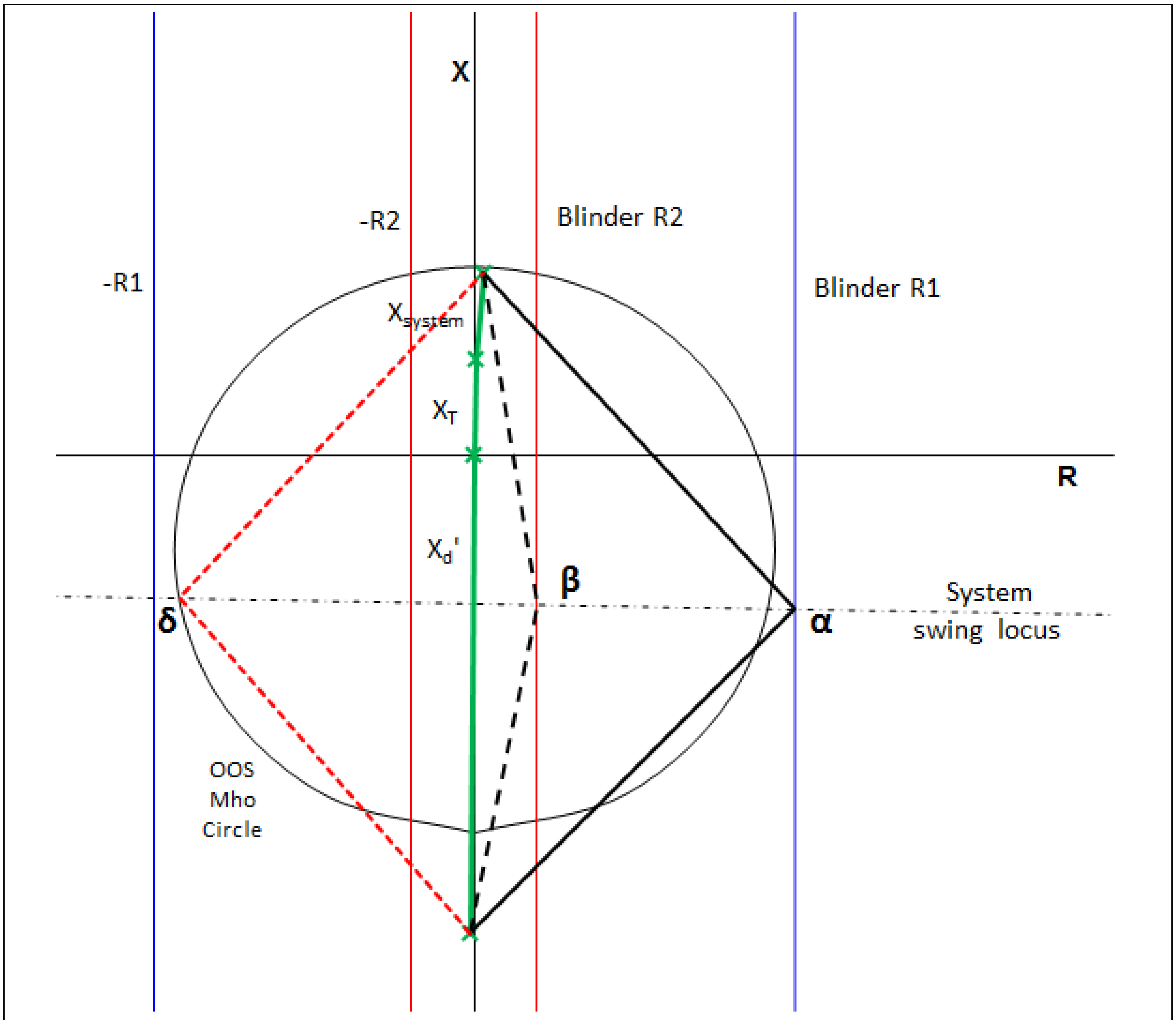

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

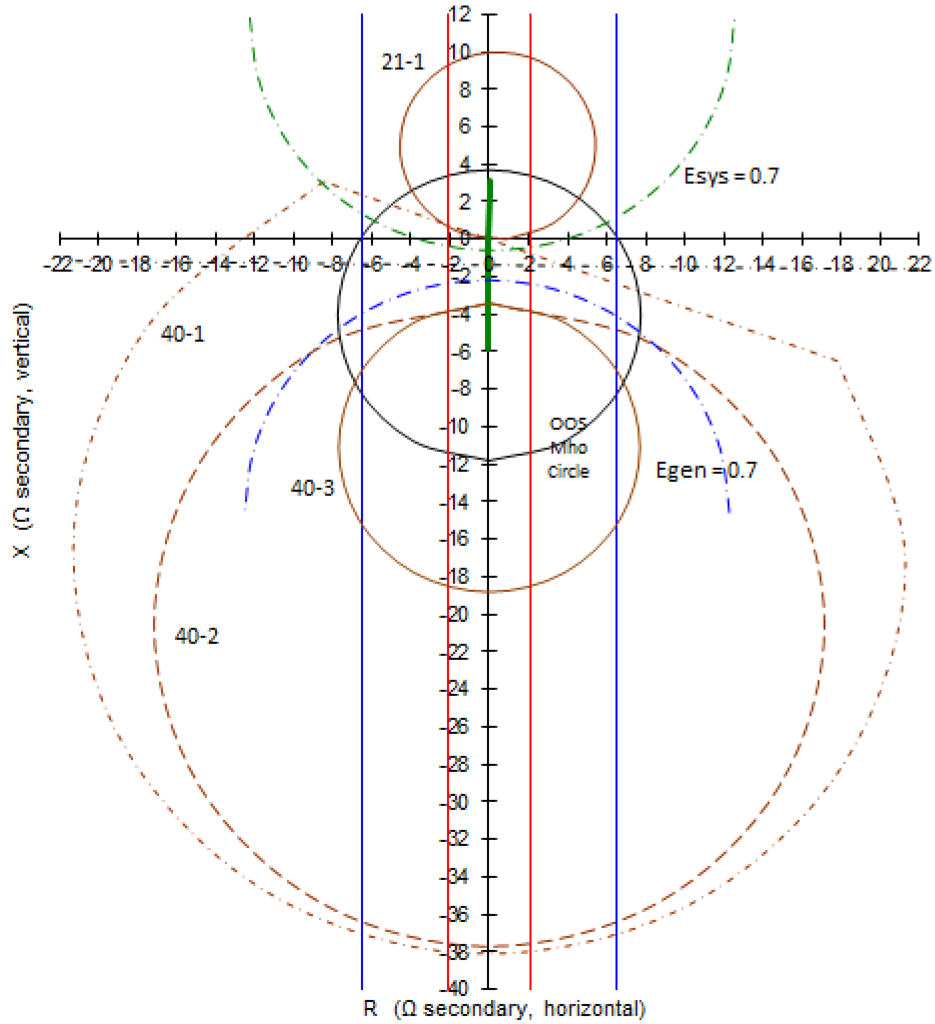

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

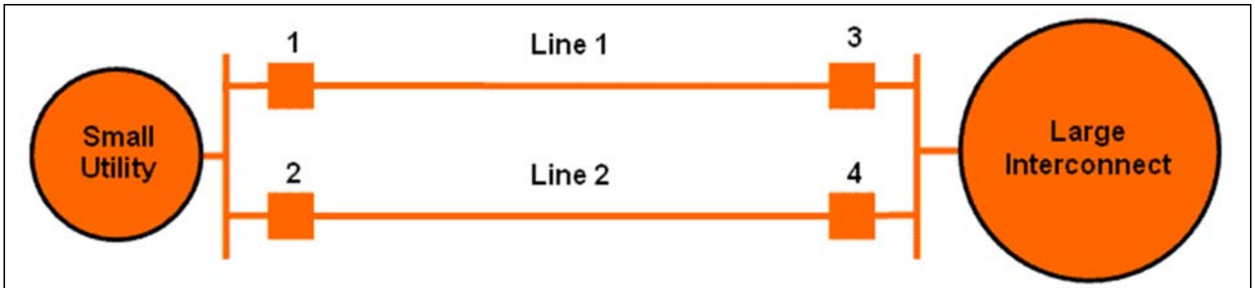

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

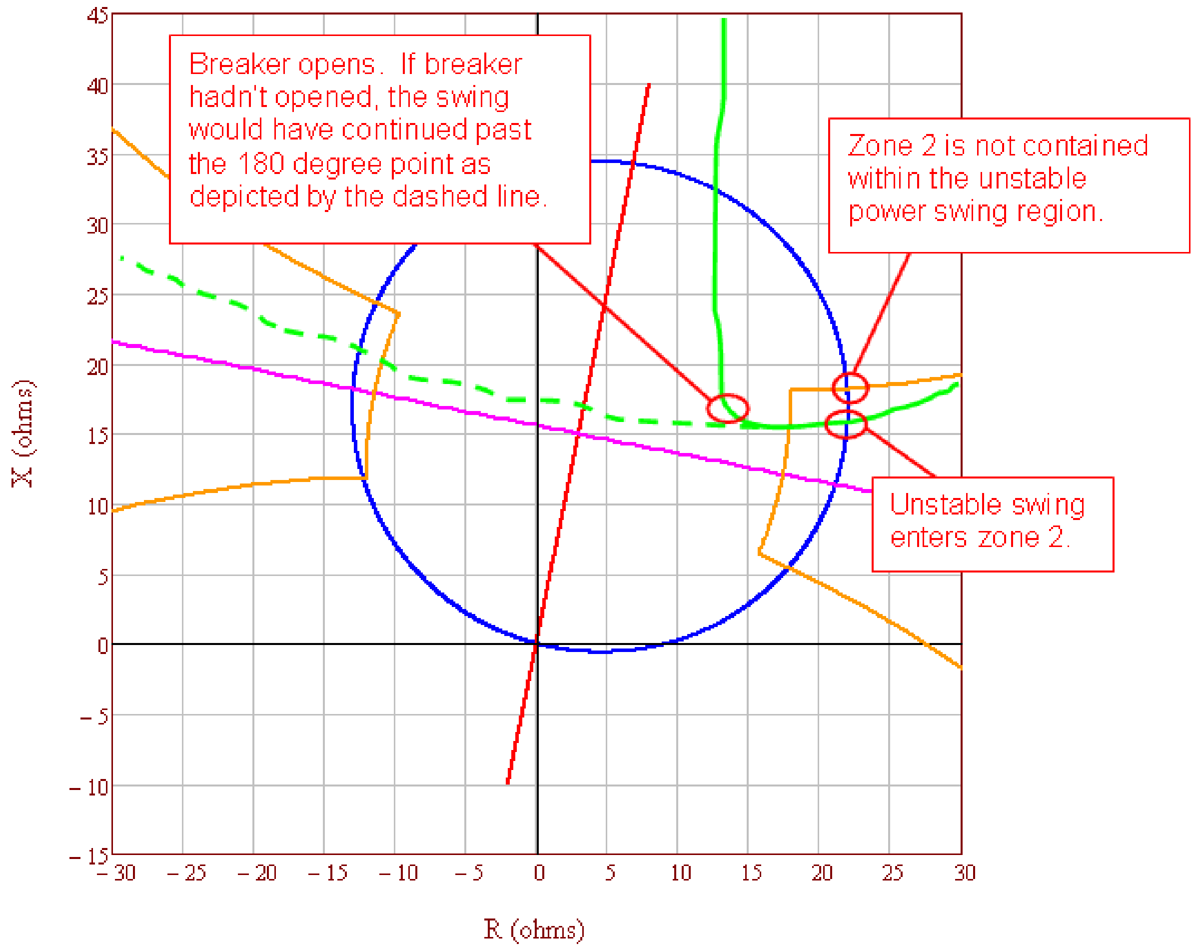

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

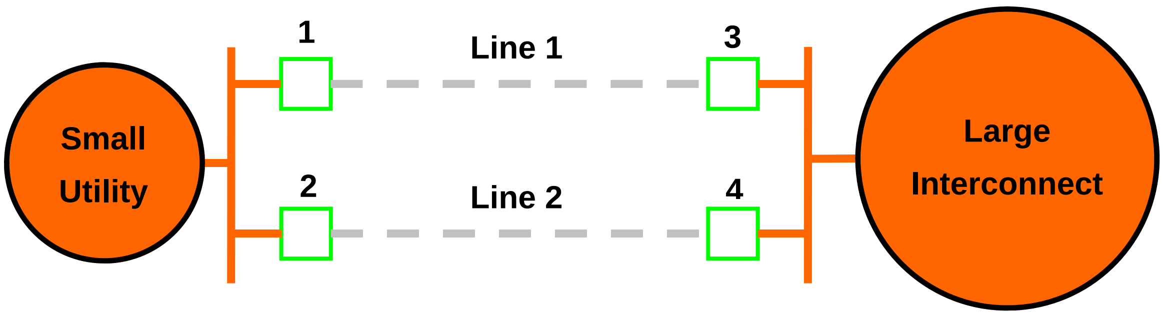

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

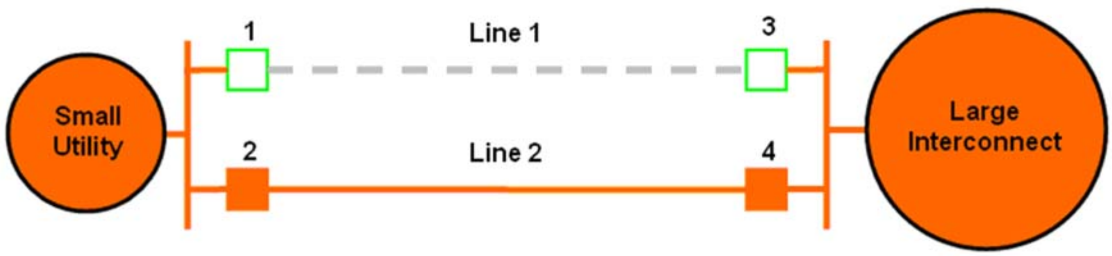

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

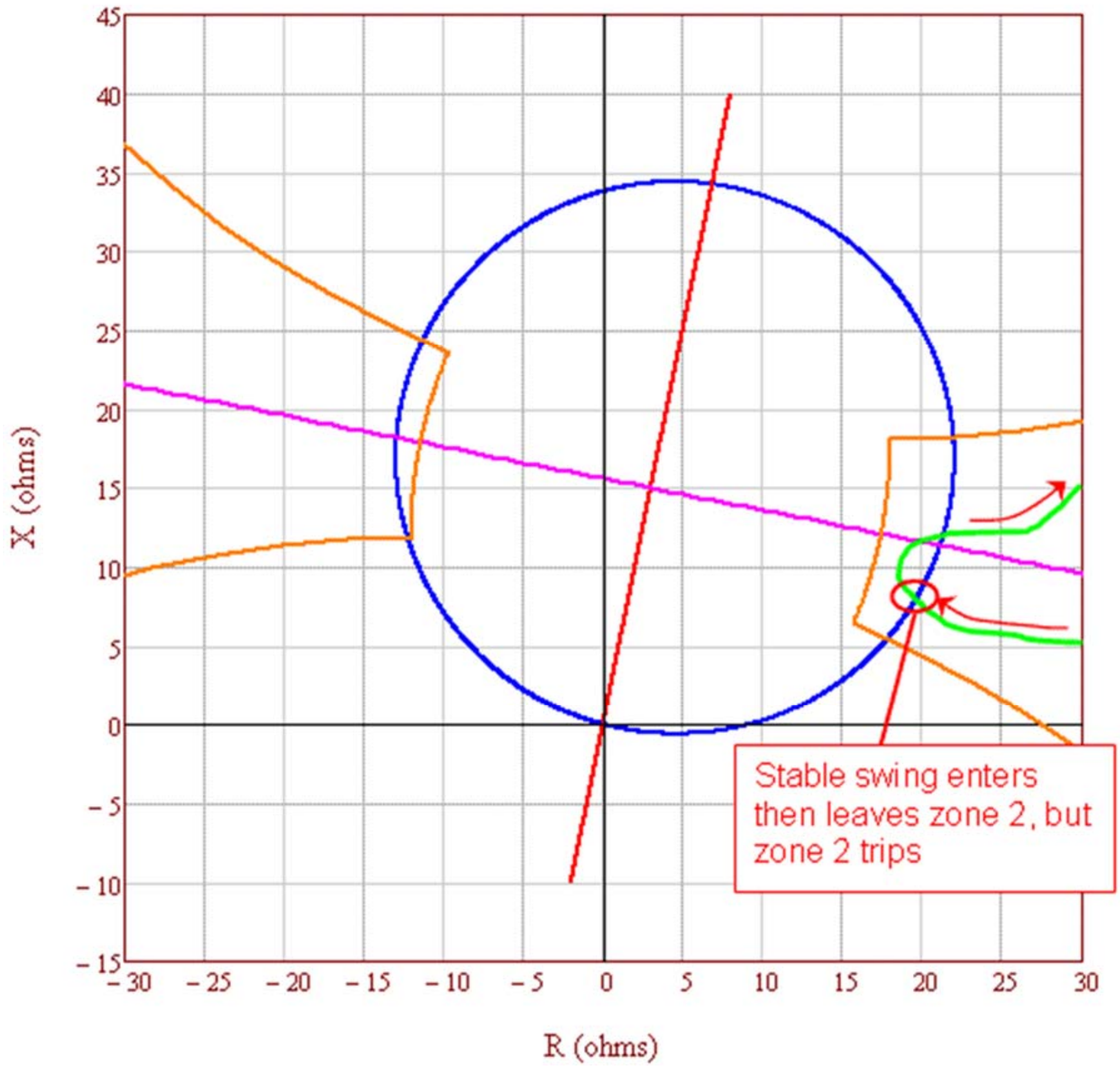

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

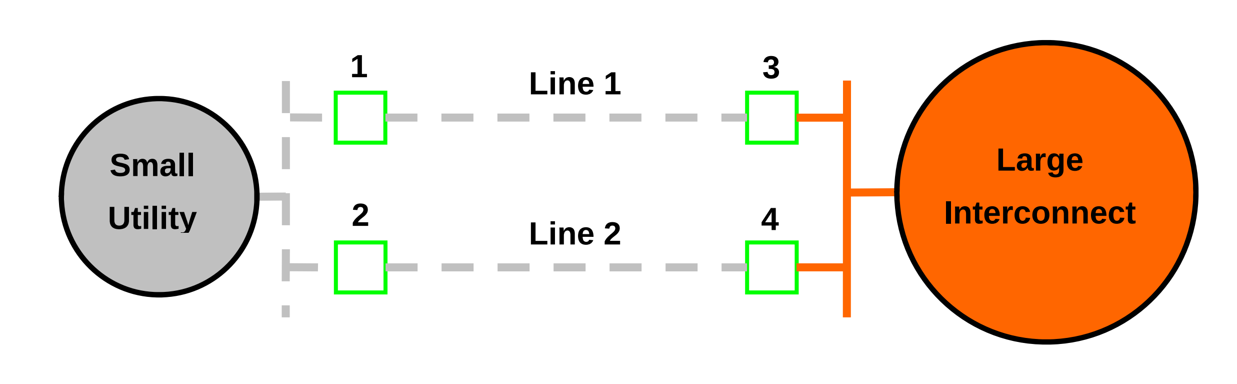

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

NERC
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RELIABILITY CORPORATION

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL ") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3)
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2)
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3)
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2)

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts.

Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.
These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that “provide” for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT’s proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]
6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that “provide” for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL “provided” for reliable pre- and post-Contingency

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[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the standard drafting team posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.

As discussed in detail below, the SDT determined that references to “most limiting criteria” and “acceptable reliability criteria”, and the manner in which the “specified system configuration” and the “pre- and post-contingency” phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

<u>Most limiting Criteria</u> – The SDT concluded that removing the “most limiting criteria” concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the “most limiting criteria.” Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the “most limiting criteria” concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing “most limiting” criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the “most limiting criteria” from the SOL definition represents an improvement to reliability. The “most limiting criteria” can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the “most limiting criteria,” if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the “most limiting criteria” exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a “most limiting criteria”, it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

Acceptable Reliability Criteria – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

Specified System Configuration – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

Pre- and Post-Contingency – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

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[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, “could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES.” The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC’s SOL methodology. There is no need to mention IROLs in the definition of SOL.

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Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits**. The electronic form must be submitted by **8 p.m. Eastern, October 10, 2018**.

Documents and information about this project are available on the project page. If you have questions, contact Principal Technical Advisor, Darrel Richardson (via email) or at (609) 613-1848.

Background

The Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. One of the primary objectives of Project 2015-09 is to make changes to the FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards and the revised definitions of Operational Planning Analysis (OPA) and Real-time Assessments (RTA).

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through FAC-011-4 Requirement R6, similar to the approach within the currently effective FAC standards, rather than through an SOL Exceedance definition. Do you agree with the performance criteria in Requirement R6?

   ☐ Yes
   ☐ No

   Comments:

2. If you have any other comments regarding FAC-011-4 **that you haven't already provided**, please provide them here.

   Comments:

3. The SDT acknowledges that requirement R6 could alternatively be located within a TOP or IRO standard; however, the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Proposed Requirement R6 was created to correspond with FAC-011-4 Requirement R6 in lieu of creating a definition for SOL Exceedance. Do you agree with Requirement R6?

   ☐ Yes
   ☐ No

   Comments:

4. If you have any other comments regarding FAC-014-3 **that you haven't already provided**, please provide them here.

   Comments:

5. The original posting of FAC-015-1 included six requirements. Industry comments to this original version indicated significant concerns. In response to these concerns, the SDT attempted to streamline and clarify the intended interactions between relevant functional entities and to consolidate the standard into fewer requirements. To achieve this the SDT:

   - Consolidated Requirements R1 – R5 in the original posting into three (R1 – R3) requirements,

- Clarified the roles of the Planning Coordinator and Transmission Planner in Requirements R1 – R3, and
- Clarified that Facility Ratings are “owner-provided” in Requirement R1.

The SDT acknowledges that some of the requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc.; however, the Project 2015-09 SAR does not currently authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Do you support the revised FAC-015-1? Please provide any other comments regarding FAC-015-1.

☐ Yes
☐ No

Comments:

6. Discussions within the SDT indicated concerns with eliminating some of the components of the approved SOL definition. While the industry feedback was largely supportive of the draft SOL definition provided in the informal posting, the SDT modified the proposed definition to incorporate some of the concepts in the approved version. The SDT believes that the revised definition posted for ballot represents an improvement over the definition provided in the informal posting. Reference the SOL rationale document for more information. Do you agree with the proposed SOL definition?

   ☐ Yes
   ☐ No

   Comments:

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

   ☐ Yes
   ☐ No

   Comments:

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Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT's proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-014-3, Requirement R7 is intended to provide a mechanism for Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL methodology. FAC-014-3, Requirement R7 addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. Therefore, this requirement focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process required in FAC-014-3 Requirement R7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don't use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement R8 requires PCs and TPs to communicate pertinent information on Corrective Action Plans (CAP) developed to address any instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon to the RC and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R7 and R8 of FAC-014-3, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL methodology (FAC-011-4). Furthermore, potentially critical stability information is communicated by planners to operators resulting an improvement in reliability by increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		Translation to New Standard or Other Action	Description and Change Justification
R1.	The Planning Authority shall have a documented SOL methodology for use in developing SOLs within its Planning Authority Area. This SOL methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-014-3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).

R2.	The Planning Authority’s SOL methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1:** **Note: 'b'**	
R2.3.2. System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1:** **Note: 'e'**	
R2.4. To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1:** **Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as “Requirements Recommended for Retirement” in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as “More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard."
R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

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Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of ~~a new FAC-015-1 Reliability Standard and~~ revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT's ~~proposal for a new FAC-015-1 Reliability Standard, along with the~~ proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL ~~M~~methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-01~~5~~4-~~1~~3, Requirement~~s~~ ~~R1~~ R7 ~~– R3 ensure~~is intended to provide a mechanism for ~~that~~ Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL ~~M~~methodology. FAC-~~015~~014-~~1~~3, Requirement~~s~~ R~~1 – R3~~7 ~~respectively~~ addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. ~~These~~ Therefore, this requirement~~s~~ focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process~~es~~ required in FAC-~~015~~014-~~1~~ 3 Requirement~~s~~ R~~1 – R3~~7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don't use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL ~~M~~methodology.

FAC-~~015~~014-~~1~~3, Requirement ~~R4~~ R8 requires PCs and TPs to communicate ~~any~~ pertinent information on Corrective Action Plans (CAP) developed to address any instability~~, Cascading or uncontrolled separation, along with key supporting information,~~ identified in ~~the~~ Planning Assessments of the Near-Term Transmission Planning Horizon to the RC~~s~~ and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements ~~R1~~ R7 ~~–~~and R~~4~~8 of FAC-014-3~~5~~, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL ~~M~~methodology (FAC-011-4~~ & FAC-014-3~~). Furthermore, potentially critical stability information is communicated by planners to operators resulting ~~. The result is~~ an improvement in reliability by ~~ensuring~~ increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)
1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)
1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)
1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.
1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:
1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:
- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R1. The Planning Authority shall have a documented SOL ~~M~~methodology for use in developing SOLs within its Planning Authority Area. This SOL ~~M~~methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-~~015~~014-~~1~~-3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL ~~M~~methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via ~~FAC-015-1, Requirement R4. IROLs are established by the RC as required by FAC-014-3.~~the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability

		Operating Limit (IROL).
R2. The Planning Authority's SOL ~~M~~methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

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R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2. System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4. To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

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	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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R3.2. Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3. Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4. Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL ~~M~~methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as “Requirements Recommended for Retirement” in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as “More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

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	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard."
R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL methodology) within its Reliability Coordinator Area. This SOL methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” The title of FAC-011-4 is “System Operating Limits Methodology for the Operations Horizon”. Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. <ins>FAC-011-4 Requirement R2</ins>: Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. <ins>Operational Planning Analysis</ins> is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R7 and Part 7.1. R7. Each Reliability Coordinator shall include in its SOL methodology 7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	011-4, Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: 6.1. System performance for no Contingencies	The items in approved FAC-011-3, Requirement R2.1 and R2.2 are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposedTOP-001-5 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.4 divide system performance requirements for the no contingency state (N-0) into each of the

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	demonstrates the following: 6.1.1. Steady State flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings. 6.1.2. Steady State voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when	three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in

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	System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded. 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. System performance for the single Contingencies listed in Part 5.1.	Part 6.2.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly identify that, in determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is an acceptable only after all other available System adjustments have been made. TOP-001-5, Requirement R25 and IRO-008-3, Requirement R7 support FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to determine SOL

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	demonstrates the following: 6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady State post-Contingency voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met. 6.2.4. Instability, Cascading or uncontrolled	exceedances in accordance with its RC's the SOL methodology.

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	separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. System Performance for applicable Contingencies identified in Part 5.2 demonstrates that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	

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	TOP-001-5, Requirement R25. R25. Each Transmission Operator shall use the applicable RC's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.. IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	FAC-011-4, Requirement R5, Part 5.1 5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4 Requirement R5, Part 5.1. FAC-011-4 Requirement R5, Part 5.1. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance

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R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	• generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : <u>FAC-011-4 Requirement R4:</u> Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; and	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs

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time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas,	and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL methodology to describe the allowed uses

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	necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.	of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed

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	2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-002-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as	retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made. Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is

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	performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system.

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	The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.4 albeit with improved language for clarity. FAC-011-4 Requirement R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: R6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following,	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5.

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along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized

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		stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.1. Specify the following single Contingency events5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any. 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.	FAC-011-4, Requirement R5, Part 5.3 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology shall:	FAC-011-4, Requirement R5, Part 5.3 and FAC-014-3 Requirement R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-014-3, Requirement R7, the Planning Coordinator is required to identify and annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term

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R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits. FAC-014-3 Requirement R7: R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include: 7.1. A requirement that the following SOL exceedances will always be communicated, within a	Transmission Planning Horizon, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.3 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	timeframe identified by the Reliability Coordinator. 7.1.1. IROL exceedances; 7.1.2. SOL exceedances of stability limits; 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation; 7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and 7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.	

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	7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator. 7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and 7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL methodology shall include] Anticipated transmission system	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL methodology the method	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4.

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configuration, generation dispatch and Load level	for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; <u>TOP-002-4, Requirement R1</u>: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). <u>IRO-008-2, Requirement R1</u>: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.	Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a “study” or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-

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	Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement R8, Part 8.2 R8.2 Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R8, Part 8.2.

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FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL methodology and any changes to that methodology, prior to the effectiveness of the methodology or of a change to the methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4: R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within an Interconnection 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL methodology within 30 days of the request if they indicate a reliability-related need for it. 8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL methodology to] Each Planning Authority and Transmission	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2.	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs

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Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	R9. Each Reliability Coordinator shall provide its SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	and TPs that are responsible for planning within the RC Area rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area.	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

Mapping Document

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs ~~(“~~(i.e., SOL Methodology~~”)~~) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” The title of FAC-011-4 is “System Operating Limits Methodology for the Operations Horizon”. Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

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		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ~~the applicable~~which owner-provided Facility Ratings are to be used in operations~~. The method shall address the use of common Facility Ratings between the Reliability Coordinator and~~ such that the Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~use common Facility Ratings. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle*	

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	and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement ~~R6~~R7 and Part ~~6~~7.1. ~~R6~~R7. Each Reliability Coordinator shall include in its SOL Methodology ~~6~~7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs~~.~~).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the	~~These requirements are addressed in:~~ ~~1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs.~~ ~~2. The definition of OPA and RTA~~	~~"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits~~

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determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	~~3.~~ FAC-011-4, Requirement ~~R4 addresses the establishment of stability limits and the associated performance requirements.~~ ~~4. FAC-011-4 Requirement~~ R6 and ~~its~~ Parts ~~relating to IROLs.~~ ~~5. The definition of IROL and the TOP and IRO standards that address operation within IROLs.~~ ~~TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).~~ ~~TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.~~	~~pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance.~~ The items in approved FAC-011-3, Requirement R2.1 and ~~its sub-requirements~~R2.2 are addressed through ~~the related TOP standards that reference SOL exceedance~~proposed FAC-011-4, Requirement R6 and its subparts as well as proposed FAC-014-3 R7. ~~1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances.~~ ~~2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA.~~ ~~3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once~~

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	~~TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.~~ ~~TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.~~ ~~IRO-008-2, Requirement R1:~~6.1, 6.2, 6.3, and 6.4. Each Reliability Coordinator shall ~~perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.~~ ~~IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational~~	~~every 30 minutes to identify SOL exceedances.~~ ~~4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances.~~ ~~5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.~~ ~~6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA.~~ ~~7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances.~~ ~~8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA.~~ ~~The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and*~~

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	~~Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.~~ ~~IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.~~ ~~IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.~~ ~~Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to*~~	~~*shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state.~~ While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System

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	~~*assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*~~ ~~Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle*~~	Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, and 6.1.3 divide system performance requirements for the pre-contingency state (N-0) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.3. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, and 6.2.3 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency

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	~~*and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"*~~ ~~FAC-011-4 Requirement R4: Each Reliability Coordinator shall~~ include in its SOL Methodology ~~the method for determining the stability limits to be used in operations. The method shall:~~ ~~4.1. Specify stability performance criteria, including any margins applied. The criteria shall include~~, at a minimum, the following~~:~~ ~~4.1.1. steady-state voltage stability;~~ ~~4.1.2. transient voltage response;~~ ~~4.1.3. angular stability;~~ ~~4.1.4. System damping.~~ ~~4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.~~	state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.2.3. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly delineate the system performance requirements related to establishing stability limits using the Contingencies identified in Requirement R5, Part 5.3. FAC-014-3, Requirement R7 supports FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to use the

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	~~4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.~~ ~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;~~ ~~4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.~~ ~~4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions.~~	performance criteria identified in the SOL Methodology. ~~Regarding the stability portions of Requirement R2, R2.1 and R2.2:~~ ~~FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.~~ ~~Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements.~~ ~~Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to~~

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	R6. ~~IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the*~~ Bulk Electric System~~.~~ performance criteria: ~~FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology:~~ ~~6.1. A description of how to identify the subset of SOLs that qualify as IROLs.~~ **6.1.** ~~6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T~~~~v~~The actual pre-Contingency state (Real-time monitoring and Real-time	~~specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology.~~ ~~Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area.~~ ~~Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the RC to establish IROLs in accordance with its SOL Methodology.~~ ~~IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's~~

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	Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following: Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time ~~,~~ ~~FAC-014-3, Requirement~~ R1~~: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology).~~ **6.1.1.** ~~IRO-009-2, Requirement R3: Each Reliability Coordinator shall act~~	~~T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment.~~ ~~Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.~~

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	~~or direct others to act so that the magnitude and~~ duration of ~~an IROL exceedance is mitigated~~those Emergency Ratings. **6.1.2.** Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits.	

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	6.1.3. Instability, Cascading or uncontrolled separation do not occur. **6.2.** The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following: **6.2.1.** Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings.	

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	Flow through a Facility must not be above the Facility's highest Emergency Rating. **6.2.2.** Voltages are within emergency System Voltage Limits. **6.2.3.** Instability, Cascading or uncontrolled separation do not occur. **6.3.** The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or	

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	uncontrolled separation does not occur. **6.4.** The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur. 6.5 In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made. FAC-014-3, Requirement ~~IROL's T_V, as identified~~R7. R7. Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs,	

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	and Real-time monitoring ~~or Real-time Assessment~~to determine SOL exceedances. ~~TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V.~~	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault ~~to ground~~ (whichever is more severe) with ~~normal clearing~~Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device;	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4~~.~~ Requirement R5, Part 5.1.1. FAC-011-4 Requirement R5, Part 5.1.1. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance requirements for anticipated post-contingency state.

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	• single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies	~~The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated."~~ The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : ~~R4.~~FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system

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R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. ~~angular~~unit stability; and 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how ~~instability risks~~stability limits are ~~identified~~determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator	performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency

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	Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes ~~(RAS)~~ and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. FAC-014-3, Requirement R8: In addressing any potential or actual SOL exceedances, each Reliability Coordinator and Transmission Operator shall allow for Non-Consequential Load Loss within their	mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4

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	Operating Plan only if all other means of System adjustments have been exhausted to prevent: • equipment damage, or • instability, Cascading, uncontrolled separation ~~1.~~2. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. ~~2.~~3. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). ~~3.~~4. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in	Requirement R6.5 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made. Regarding ~~The~~FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the

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	Requirement R2 to its Reliability Coordinator. ~~4.~~5. TOP-012-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. ~~5.~~6. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. ~~6.~~7. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in	Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is

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	its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 8. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.5 albeit with improved language for clarity. FAC-011-4 Requirement R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria:	addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.5, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. ~~Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather than a NERC Reliability Standard requirement.~~

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	R.6.5 In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.	
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is

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		needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall ~~include~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~Contingency events for use in determining stability limits and performing Operational Planning ~~Analyses~~Analysis (OPAs) and Real-time Assessments (RTAs~~).~~)	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	for the area under study. The ~~method~~SOL Methodology shall ~~include~~: 5.1. ~~The~~Specify the following ~~list of~~ single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with ~~normal clearing~~Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. ~~Any~~Identify any additional ~~types of~~ single ~~Contingency events identified for use in determining stability limits,~~ or multiple	

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	Contingency events or types of Contingency events for use in performing OPAs and RTAs. 5.3. ~~Any types of~~ Identify any additional single or multiple Contingency events ~~identified~~or types of Contingency events for use in determining stability limits~~, or for use in performing OPAs and RTAs~~. 5.4. ~~The~~Describe the method(s) for ~~considering~~identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement ~~R6~~R4, to ~~identify the Contingencies for~~ use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall ~~include~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~ Contingency events for use in determining stability limits and performing Operational Planning ~~Analyses~~Analysis (OPAs) and Real-	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement ~~R6~~R4 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-015-1, Requirement ~~R6~~R4, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the

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the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	time Assessments (RTAs~~).~~) for the area under study. The ~~method~~SOL Methodology shall ~~include:~~ 5.4. ~~The~~Describe the method(s) for ~~considering~~identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1, Requirement ~~R6~~R4, to ~~identify the Contingencies for~~ use in determining stability limits. FAC-015-1 Requirement ~~R6~~R4: ~~R6~~R4. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	related information contained in the Parts of Requirement ~~R6~~R4, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); ~~6~~4.2 The associated stability criteria used as part of determining the instability; ~~6~~4.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; ~~6.4~~ 4.4 A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified; 4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and 4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes ~~(RAS)~~ and other automatic post-Contingency mitigation ~~actions[1]~~actions.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by ~~including other automatic mitigation actions that are not a RAS, for example UVLS.~~ adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.

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	~~Footnote 1 states "The planned~~ 4.7 State that the use of underfrequency load-~~ ~~shedding (UFLS) ~~is~~programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits~~."~~.	
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how ~~instability~~stability limits are determined, instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis*	Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.

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	may be provided through internal systems or through third-party services.)"	
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement ~~R6~~R7, Part ~~6~~7.2 R6.2 Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement ~~R6~~R7, Part ~~6~~7.2.
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement ~~R8~~R9, Parts ~~8~~9.1, 9.2.1 and ~~8~~9.2.4: ~~R8~~R9. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: ~~8~~9.1. Each ~~adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;~~ ~~8.4. Each requesting~~ Reliability Coordinator that requests and indicates it has a reliability-related need ~~and is not considered adjacent in Part 8.1,~~ within 30 ~~calendar~~ days of ~~receiving the~~a request~~.~~	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement ~~R8~~R9, Parts ~~8~~9.1, 9.2.1 and ~~8~~9.2.4. ~~Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it.~~

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	9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within an Interconnection 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's Methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in ~~Part 8~~Parts 9.1 and 9.2.4~~,~~., do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with ~~Part 8~~Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it. Part 9.2 also includes a requirement to provide the SOL Methodology as soon as practicable if a change was necessary to address a reliability issue. This provides flexibility for an RC to make reliability needed changes to its SOL Methodology quickly.
FAC-011-3, Requirement R4, R4.2	FAC-011-4, Requirement ~~R8~~R9, Part ~~8~~9.2 and subpart 9.2.2.	The language was changed to better reflect the intent of the requirement. The

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	~~R8.~~R9. Each Reliability Coordinator shall provide its ~~new or revised~~ SOL Methodology to: ~~8~~9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area ~~prior to the effective date of the SOL Methodology~~;	requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area~~.~~ rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement ~~R8~~R9, Part ~~8~~9.2 and subpart 9.2.3. ~~R8~~R9. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: ~~8.3~~9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area ~~prior to the effective date of the SOL Methodology;~~.	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement ~~R8~~R9, Part ~~8~~9.2. and Subpart 9.2.3.

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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<u>FAC-014-2, Requirement R1</u> R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	<u>Requirements R1, R2, and R4 of FAC-014-3</u> R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

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		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

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Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
<u>FAC-014-2, Requirements R3 and R4</u> R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 <u>FAC-011-4, Requirement R9, Part 9.2:</u> **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

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	planning any portion of the Reliability Coordinator Area; FAC-014-3 Requirement R6: **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning	

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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. IRO-014-3, Requirement R1 R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:	

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	1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-

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	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. <u>MOD-029-2a, Requirement R4:</u> R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. <u>MOD-030-3, Requirement R2.6:</u> [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
<u>FAC-014-2, Requirement R5, R5.3 and R5.4</u> R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-014-3, Requirements R7 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning

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and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g.	Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

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	violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. <u>MOD-028-2, Requirement **R7**:</u> **R7**. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: **R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations. **R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations. <u>MOD-029-2a, Requirement **R4:**</u> **R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the	With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement **R2.6**: **R2.6.** [The TOP shall…] Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	

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FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-014-3, Requirement R7 (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all

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		instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Mapping Document for FAC-014-2

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<u>FAC-014-2, Requirement R1</u> R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	<u>Requirements R1, R2, and R4 of FAC-014-3</u> R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

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		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

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Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	FAC-011-4, Requirement ~~R8~~R9, Part ~~8~~9.2, Subpart 9.2.2 FAC-015-1, Requirements ~~R 1 – R6~~R1 – R3 FAC-011-4, Requirement ~~R8~~R9, Part ~~8~~9.2: **R9.** ~~R8.~~Each Reliability Coordinator shall provide its ~~new or revised~~ SOL Methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* **9.2** ~~8.2.~~ Each of the following entities 30 days prior to the effective date of the SOL methodology or as soon as	The SDT is proposing a construct that does not make use of an SOL Methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL Methodology. The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement ~~R8, Part 8~~R9, Part 9.2.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the

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	practicable if a change must be implemented in less than 30 days to address a reliability issue: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area ~~prior to the effective date of the SOL Methodology~~; FAC-015-1 Requirement R1 – R3: **1.** ~~R1.~~ Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than ~~those established~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~	stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes ~~made to~~in the proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ~~ensures~~ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings ~~used in Planning Assessments~~, Requirement R2 addresses the System steady state voltage limits ~~used in Planning Assessments~~, and Requirement R3 addresses the stability performance criteria used in Planning

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	The process may allow the ~~Planning Coordinator uses~~use of less limiting Facility Ratings ~~than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* • ~~R2.~~ The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan, • Facility Rating differences are due to variations in ambient temperature assumptions, • The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator, or • The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected	Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning. ~~Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology.~~ ~~FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs.~~ ~~FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings,~~

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	Planning Coordinator and Reliability Coordinator. **2.** Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-~~-~~-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits ~~established~~used in ~~accordance with its operations per the~~ Reliability Coordinator's SOL Methodology. ~~If~~The process may allow the ~~Planning Coordinator uses~~use of less limiting System steady-state voltage limits ~~than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* • ~~R3.~~ The Planning Coordinator provides a technical rationale for using a less limiting System steady-state voltage limit	~~System steady-state voltage limits, and stability criteria provided by its PC.~~ By implementing Requirements R1 – ~~R5~~R3 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. ~~FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.~~

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	to each affected Transmission Planner and Reliability Coordinator, or • The Transmission Planner provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Planning Coordinator and Reliability Coordinator. **3.** Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria ~~established~~used in ~~its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~The process may allow the ~~Planning Coordinator uses~~use of less limiting stability performance criteria ~~than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if: *[Violation Risk Factor:*	

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	Medium] [Time Horizon: Long-term Planning] ~~R4. Each~~The Planning Coordinator ~~shall provide the Facility Ratings, System steady-state voltage limits, and~~ provides a technical rationale for using a less limiting stability performance ~~criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.~~ • ~~R5. Each~~criterion to each affected Transmission Planner ~~shall use Facility Ratings, System steady-state voltage limits, and~~ and Reliability Coordinator, or The Transmission Planner provides a technical rationale for using a less limiting stability performance ~~criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.~~ • ~~R6. Each~~criterion to each affected Planning Coordinator ~~shall communicate any instability, Cascading or uncontrolled separation identified in~~	

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	~~either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted~~ and Reliability Coordinator ~~and Transmission Operator. This communication shall include:~~. ~~6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~ ~~6.2 The associated stability criteria used as part of determining the instability;~~ ~~6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;~~ ~~6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;~~ ~~6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~	

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<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information: R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL;	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); ~~and~~ ~~5.2.5.~~5.2.5. A description of the associated system conditions; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information	

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	within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its	

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	Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s). The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its

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	R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work	1. FAC-015-1, Requirements R1 – ~~R6~~R4 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-015-1~~,~~ Requirements **R1** –~~R6:~~ **R3** (See Requirements **R3** and **R4** section above.) ~~R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more~~	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. ~~Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology.~~

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within its Transmission Planning Area and to adjacent Transmission Planners.	~~limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ ~~R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ ~~R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are~~	~~FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments.~~ ~~FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC.~~ ~~FAC-015-1, Requirements R1 – R5 result in PC~~FAC-015-1, Requirements R1 – R3 result in PCs and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria

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	~~equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~ **R4.** Each Planning Coordinator ~~shall provide the Facility Ratings, System steady-state voltage limits,~~ and ~~stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.~~ ~~R5. Each~~each Transmission Planner ~~shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.~~ ~~R6. Each Planning Coordinator~~ shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term	established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement ~~R6~~R4 requires the PC and TP to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments ~~to the RC~~ and Transfer Capability assessments to impacted RCs, TOPs~~.~~, TOs, and GOs. The subparts of Requirement ~~R6~~R4 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. This information is also necessarily communicated to TOs and GOs for their use in identifying Facilities that require higher levels of vegetative management or cyber protection. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and

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	Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: ~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); ~~6~~4.2 The associated stability criteria used as part of determining the instability; ~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation; ~~6.4~~4.4 A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified; 4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to	Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	address the instability, Cascading or uncontrolled separation; 4.**6**~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. MOD-028-2, Requirement **R7**: **R7**. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: **R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations. **R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement **R4:** **R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	MOD-030-3, Requirement **R2.6**: R2.6. [The TOP shall…] ~~R2.6.~~ Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-015-1, Requirement ~~R6~~R4 ~~R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include:~~ ~~6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~ ~~6.2 The associated stability criteria used as part of determining the instability;~~ ~~6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;~~ ~~6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;~~	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows: • FAC-015-1, Requirement ~~R6~~R4 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement ~~R6~~R4 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement ~~R6~~R4 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~(See Requirements **R5.3** and **R5.4** section above.)	• FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement ~~R6~~R4 because all instances of instability identified by the PC are to be communicated to the RC in accordance with FAC-015-1, Requirement ~~R6~~R4. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement ~~R6~~R4s both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Mapping Document for Reliability Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 ensures Planning Coordinators (PC) and Transmission Planners (TP) use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirement R4 requires PCs and TPs to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R4 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in the body of NERC Reliability Standards that are affected by the proposed retirement of FAC-010-3 and the proposed action by the SDT.

NERC Reliability Standard Requirements Affected by the Retirement of FAC-010-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
CIP-002-5.1a **Attachment 1 (Section 2 – Medium Impact):** **2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	**CIP-002-5.1a Revision** **Attachment 1 (Section 2 – Medium Impact):** **2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result instances of instability, Cascading, or uncontrolled separation.	The proposed retirement of FAC-10-3 will result in PCs and TPs no longer being required to establish IROLs in accordance with a PC SOL Methodology. Therefore, the SDT is proposing a modification to criterion 2.6 of Attachment 1 to: • Remove the IROL reference, • Limit the relevant functional entities to the PC and TP, and • Incorporate Contingency events included in the Planning Assessment that result in instability, Cascading, or uncontrolled separation as a replacement for the use of IROLs in the identification of medium impact Facilities. IROLs established by the RC is not an appropriate qualifier in the determination of Facilities that require cyber-related hardening. These limits are determined in operational and real-time horizons and may be highly specific, temporary, or sudden onset types of events. The identification of these Facilities is more

2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.	2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would result in instability, Cascading or uncontrolled.	appropriately based on long-term planning studies where their criticality to the System can be determined in a more consistent and practical manner. Contingency events included in the Planning Assessment that result in instability, Cascading, or uncontrolled separation, incorporate the severe impacts currently associated with IROLs so the intent of the criterion is preserved. These events are required to be documented in the PC's and TP's Planning Assessments and identify Facilities that, when compromised, potentially result in severe impacts and thus, may require certain levels of CIP protection. TPL-001-4 Table 1 requires that the PC consider events experienced in operations in its Planning Assessments (item 2f and 3b for stability and steady state, respectively). Accordingly, the removal of the IROL term from this standard does not preclude the PC and RC from working together to identify Facilities that may warrant a higher level of CIP protection.
Current CIP-014-2 **A. Introduction (Section 4 – Applicability):** **4.1.1.3** Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	**CIP-014-2 Revision** **A. Introduction (Section 4 – Applicability):** **4.1.1.3** Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result instances of instability, Cascading, or uncontrolled separation.	The proposed retirement of FAC-10-3 will result in PCs and TPs no longer being required to establish IROLs in accordance with a PC SOL Methodology. Therefore, the SDT is proposing a modification to criterion 4.1.1.3 of the Applicability section to: • Remove the IROL reference, • Limit the relevant functional entities to the PC and TP, and • Incorporate Contingency events included in the Planning Assessment that result in instability, Cascading, or uncontrolled separation as a replacement for the use of IROLs in the identification of medium impact Facilities. IROLs established by the RC is not an appropriate qualifier in the determination of Facilities that require cyber-related hardening. These limits are determined in operational and real-time horizons and may be highly specific, temporary, or sudden onset types of events. The identification of these Facilities is more appropriately based on long-term planning studies where their criticality to the System can be determined in a more consistent and practical manner.

		Contingency events included in the Planning Assessment that result in instability, Cascading, or uncontrolled separation, incorporate the severe impacts currently associated with IROLs so the intent of the criterion is preserved. These events are required to be documented in the PC's and TP's Planning Assessments and identify Facilities that, when compromised, potentially result in severe impacts and thus, may require certain levels of CIP protection. TPL-001-4 Table 1 requires that the PC consider events experienced in operations in its Planning Assessments (item 2f and 3b for stability and steady state, respectively). Accordingly, the removal of the IROL term from this standard does not preclude the PC and RC from working together to identify Facilities that may warrant a higher level of CIP protection.
Current FAC-003-4 **A. Introduction (Section 4 – Applicability):** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	**FAC-003-4 Revision** **Introduction (Section 4 – Applicability):** **4.2.2.** Each overhead transmission line, operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. **4.3.1.2.** Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation; or …	The Applicability section (4) of the Introduction defines the use of the term "applicable lines" that is used in the requirements of this standard. These "applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. It is important to note the following: • All overhead transmission lines that operate at 200 kV and above are included as "applicable lines" (4.2.1 & 4.3.1.2). The implication is that higher voltage transmission lines tend to be more critical to the bulk electric infrastructure and thus require higher level of right-of-way maintenance to ensure encroachments are mitigated. • Qualifications are then made to include < 200 kV overhead transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The IROL designation (as identified by the PC) is used as one such qualifier. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management requirements.

		The proposed revisions to the "Applicability" section improves on the ambiguity associated with using the IROL term. This proposal replaces the phrase "identified as an element of an IROL" with "identified by the Planning Coordinator or Transmission Planner, pursuant to FAC-015-1 Requirement R4, that identify instances of instability, Cascading, or uncontrolled separation." This proposal preserves the intent of the current criteria with the inclusion of the elements associated with IROLS (instability, Cascading, or uncontrolled separation). The proposed FAC-015-1 includes Generation Owners and Transmission Owners as recipients of this information so the mechanism for the appropriate communication is addressed.
Current FAC-003-4 **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below…	**FAC-003-4 Revision** **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated Electrical Operating Conditions of the types shown below…	As stated in the FAC-003 rationale, "Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities." The rationale further explains the separation of the two requirements as follows: "The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant." As a result, the Violation Risk Factor (VRF) was set at "high" for R1 and "medium" for R2. In FERC Order 777 (2013), FERC directed NERC to change the VRF for R2 from "medium" to "high" (paragraph 77) based on transmission lines that were not part of an IROL or Major WECC Transfer Path contributing to cascading outages in the past. This removed the only difference between the two Requirements R1 and R2, resulting in complete redundancy between the two requirements. Therefore, the identification as "an element of an IROL, or an element of a Major WECC Transfer Path" wording in Requirements R1 and R2 is not necessary since all "applicable lines" are subject to the same MVCD criteria and have the same level of criticality. The resulting proposed language simplifies the requirement by removing this unnecessary verbiage.

Current FAC-003-4 **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	**FAC-003-4 Revision** **R2.** Retire	As stated in the FAC-003 rationale, "Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities." The rationale further explains the separation of the two requirements as follows: "The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant." As a result, the Violation Risk Factor (VRF) was set at "high" for R1 and "medium" for R2. In FERC Order 777 (2013), FERC directed NERC to change the VRF for R2 from "medium" to "high" (paragraph 77) based on transmission lines that were not part of an IROL or Major WECC Transfer Path contributing to cascading outages in the past. This removed the only difference between the two Requirements R1 and R2, resulting in complete redundancy between the two requirements. Therefore, the SDT is proposing the retirement of Requirement R2 with the modifications to Requirement R1.
FAC-013-2 **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs). **R1.3** A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.	**Proposed FAC-013-2** **R1.2 –** Retire **R1.3** A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessment. **Proposed FAC-011-4** **R9.** Each Reliability Coordinator shall provide its SOL Methodology to: **R9.2** Each of the following entities prior to the effective date of the SOL methodology: **R9.2.2** Each Planning Coordinator and Transmission Planner that is	Requirement R1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The use of SOLs, used in operations, may not be applicable here unless there is a known operating condition that has been communicated by the RC or TOP that is likely to recur on a somewhat regular basis. Otherwise, performance criteria should be consistent with that outlined in TPL-001-4. Requirement R1 Part 1.3 in FAC-013-2 states that "assumptions and criteria" in the TCA should be consistent with PC's "planning practices". These planning practices are governed by the requirements of TPL-001. Therefore, the SDT is proposing a modification to clarify Requirement R1 Part 1.3 by replacing "planning practices" with "Planning Assessment". With the SDT's proposed FAC-015-1, the "assumptions and criteria" involving Facility Ratings, System steady-state voltage limits, and stability performance criteria (the three components of SOLs used in operations) would be bounded by the RC's SOL

	responsible for planning any portion of the Reliability Coordinator Area **Proposed FAC-015-1** **R1.** Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] • The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan, • Facility Rating differences are due to variations in ambient temperature assumptions, • The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator, or • The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.	Methodology. The RC's SOL Methodology is provided to PCs and TPs via the SDT's proposed FAC-011-4 Requirement R9.2.2. In addition, it is important to note that coordination of "Contingencies on adjacent Systems" between neighboring planning entities is required in TPL-001-4, Requirements R3.4.1 & R4.4.1. Therefore, the intent of FAC-013-2 Requirement R1.2 has been addressed by more recent requirement language in the current TPL-001-4 and the proposed FAC-015-1 and FAC-011-4 standards. For this reason the SDT proposes the retirement of this requirement due to its redundancy with TPL-001-4 and the proposed FAC-015-1.

	R2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting System steady-state voltage limits if: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] • The Planning Coordinator provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Transmission Planner and Reliability Coordinator, or • The Transmission Planner provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Planning Coordinator and Reliability Coordinator. **R3.** Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting stability performance criteria if: [Violation	

	Risk Factor: Medium] [Time Horizon: Long-term Planning] • The Planning Coordinator provides a technical rationale for using a less limiting stability performance criterion to each affected Transmission Planner and Reliability Coordinator, or • The Transmission Planner provides a technical rationale for using a less limiting stability performance criterion to each affected Planning Coordinator and Reliability Coordinator. TPL-001-4 **R3.4** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R3, Part 3.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. (Requirement **R4.4** & **R4.4.1** contain the same wording)	
FAC-014-2	Requirements **R3** – **R5**	Under revision in conjunction with Project 2015-09

Current PRC-002-2 **A. Introduction (Section 4 – Applicability):** **4.1** The Responsible Entity is: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator	**PRC-002-2 Revision** **A. Introduction (Section 4 – Applicability):** **4.1** Reliability Coordinator	Removing the Planning Coordinator as an entity responsible for Requirement 5 and placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which dynamic Disturbance recording (DDR) data is Required. Requirement R5.4 requires a revaluation of the list at least once every 5 calendar years. Reliability Coordinators (RC) have all of the necessary information to address 5.1.1. – 5.1.5. Planning Coordinators lack first-hand information on System Operating Limits or Interconnection Reliability Operating Limits unless provided by the RC. (PCs do not have "operating" limits, but may utilize planning limits and criteria). The RC also receives detailed stability-related information from the PC (and Transmission Planners) via the proposed FAC-015 Requirement R4. This information may be utilized by the RC to establish stability-related SOLs (including IROLs). This facilitates coordination between planning entities and the RC. Moreover, consistency across larger areas (fewer RCs than PCs) will be gained as well.
Current PRC-002-2 **R5.** Each Responsible Entity shall:	**PRC-002-2 Revision** **R5.** Each Reliability Coordinator shall:	Requirement R5 was modified to reflect the proposed changes to the Applicability Section.
Current PRC-023-4 **Attachment B (Criteria Section):** If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… **B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the	**PRC-023 Revision** **Attachment B (Criteria Section):** If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… **B2.** The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.	The Applicability section (4) of the Introduction identifies the circuits that are subject to the requirements of PRC-023-4. These circuits are defined to be: • Transmission lines operated at 200 kV and above. • Transformers with low voltage terminals connected at 200 kV and above. • Transmission lines/transformers, operated/connected at less than 200 kV, that are identified in accordance with Requirement R6 of PRC-023-4. Requirement R6 of PRC-023-4 requires an annual assessment by the PC to determine the applicable circuits by applying criteria in Attachment B of the

IROL was determined in the planning horizon pursuant to FAC-010.		standard. The criteria in the attachment are to be applied to circuits in the PC area to determine if any sub 200 kV circuits are critical enough to merit the same protection requirements of higher (200 kV +) voltage circuits. The IROL designation (as identified by the PC) is used as one such criteria (B2). The actual limit is not the focus, but rather, the identification of circuits that merit the same protection procedures of higher voltage lines. The SDT's proposal to modify criterion B2, in conjunction with the retirement of FAC-010, does not create a reliability gap for the following reasons. • The comprehensive requirements in TPL-001-4 are better suited to address the potential criticality of Transmission Facilities including those that, when compromised, potentially result in instability, Cascading, or uncontrolled separation. • TPL-001-4 Table 1 requires that the PC consider events experienced in operations in its Planning Assessments (item 2f and 3b for stability and steady state, respectively). Accordingly, the removal of the IROL term from this standard does not preclude the PC and RC from working together to identify Facilities that are applicable to this standard. • The proposed revision to criterion B2 improves on the ambiguity associated with using the IROL term. This proposal preserves the intent of the current criterion by specifying circuits identified by the PC that, when compromised, could be associated with instability, Cascading, or uncontrolled separation. The proposal also incorporates coordination with the Facility Owner (similar to criterion B5) in the identification of these Facilities.
Current PRC-026-1 **R1.** Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner:	**Revised PRC-026-1** **R1.** Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria:	The proposed retirement of FAC-010 necessitates an update of the language in Requirement R1 (and the associated footnote) of PRC-026-1 since a Planning Coordinator SOL methodology will no longer be required. The SDT's proposed modification to R1 is to replace the SOL reference with updated language that ties to Elements associated with an angular instability identified in the Planning Assessment. This proposed modification maintains the intent of the requirement in that Elements that fit the criteria of R1 are to be communicated appropriately.

Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	1. Generator(s) where an angular stability constraint exists that, is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s). 2. Elements associated with angular instability identified in Planning Assessments.	
BAL Standards	No Action Required	
COM Standards	No Action Required	
EOP Standards	No Action Required	
INT Standards	No Action Required	
IRO Standards	No Action Required	
MOD Standards	No Action Required	

NUC Standards	No Action Required
PER Standards	No Action Required
TOP Standards	No Action Required
TPL Standards	No Action Required
VAR Standards	No Action Required

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance criteria could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 7.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 7.1 and 7.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance criteria could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	Moderate	High	Severe
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7~~6~~	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7~~6~~			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part ~~6~~7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part ~~6~~7.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part ~~6~~7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts ~~6~~7.1 and ~~6~~7.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R7~~6~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8~~7~~	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R~~87~~			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R8~~7~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R9~~8~~	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9~~8~~			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days~~The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.~~	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.~~The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.~~	The Reliability Coordinator failed to provide its new or revised SOL Methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.~~The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3.~~ ~~OR~~ ~~The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20~~	The Reliability Coordinator failed to provide its new or revised SOL Methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.~~The~~

		~~calendar days but less than or equal to 30 calendar days.~~	~~Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3.~~ ~~OR~~ ~~The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology.~~ ~~OR~~ ~~The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days.~~ ~~OR~~ ~~The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.~~

VSL Justifications for FAC-011-4, Requirement R~~9~~8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to~~did not~~ establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to~~did not~~ establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to~~did not~~ provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator failed to~~did not~~ provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to~~did not~~ determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.6~~5~~.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.6~~5~~.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.6~~5~~.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.6~~5~~.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~VRF Justifications for FAC-014-3 Requirement R6~~	
~~Proposed VRF~~	~~High~~

~~This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.~~

~~VSLs for FAC-014-3, Requirement R6~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.~~

~~VSL Justifications for FAC-014-3, Requirement R6~~	
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~**FERC VSL G4**~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R6			
Lower	Moderate	High	Severe
N/A	N/A	N/A	A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in Planning Assessments are equally limiting or more limiting than the stability performance criteria established in the Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R4, Parts 4.1 – 4.6. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A~~The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.~~The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.~~The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A~~The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~	The Planning Coordinator or a Transmission Planner used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.~~The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.~~The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A~~The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.~~	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.~~The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its SOL Reliability Coordinator's SOL Methodology, but did not document the technical justification.~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in Planning Assessments are equally limiting or more limiting than the stability performance criteria established in the Reliability Coordinator's SOL Methodology.~~The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~VRF Justifications for FAC-015-1 Requirement R4~~	
~~Proposed VRF~~	~~Medium~~

~~This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.~~

~~VSLs for FAC-015-1, Requirement R4~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide one element of the required information.~~	~~The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners.~~ ~~OR~~ ~~The Planning Coordinator failed to provide two or more elements of the required information.~~

~~VSL Justifications for FAC-015-1, Requirement R4~~	
~~**FERC VSL G1**~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement maps to the previously approved Requirement R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.~~
~~**FERC VSL G2**~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~**FERC VSL G3**~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~**FERC VSL G4**~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

~~VRF Justifications for FAC-015-1 Requirement R5~~	
~~Proposed VRF~~	~~Medium~~

~~This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.~~

~~VSLs for FAC-015-1, Requirement R5~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.~~

~~VSL Justifications for FAC-015-1, Requirement R5~~	
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement maps to the previously approved Requirement R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

VRF Justifications for FAC-015-1 Requirement R4~~6~~	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R4~~6~~ of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4~~6~~			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R4~~6~~, Parts ~~6~~4.1 – ~~6~~4.6~~5~~.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R4~~6~~, Parts ~~6~~4.1 – ~~6~~4.6~~5~~.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R4~~6~~, Parts 4~~6~~.1 – ~~6~~4.6~~5~~.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R4~~6~~, Parts ~~6~~4.1 – ~~6~~4.6~~5~~. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R4~~6~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Rationales for FAC-010-3 (Retirement) and FAC-015-1

May 2018

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning Coordinator (PC) must have a documented methodology for establishing SOLs (including IROLs) within its PC Area for the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires PCs and Transmission Planners (TPs) to establish and communicate SOLs and IROLs, used in the planning horizon, that are consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, such as the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically:

- The retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4.
- All of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3.
- All of the IRO standards have been modified.

The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address, in some manner, the foundational concept of reliable System performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO Reliability Standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC Reliability Standards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC Reliability Standards by minimizing redundancy, allowing for better continuity in the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable System performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a documented methodology for establishing SOLs for use in the planning horizon. Additionally, the SDT also proposes the retirement of the corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs was unnecessary and not useful for ensuring reliable planning or Reliable Operation. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. Supplementally, the SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

Under the current construct, PCs and RCs may have significantly different SOL Methodologies as the currently-effective Reliability Standards (FAC-010-3, FAC-011-3 & FAC-014-2) do not have any link requiring coordination between the methodologies. Furthermore, the nature of the current construct does not address continuity between planning and operations and may potentially result in a System not adequately planned for operational needs. The SDT's proposed changes help address the potential for inconsistencies between the PC's SOL Methodology and the RC's SOL Methodology.

Additionally, because of the evolution of the TPL standards, there are many redundancies in the responsibilities for PCs and TPs between those in FAC-010/FAC-014 and those in TPL-001-4. In fact, planners are under no obligation to use the PC's SOL Methodology for their Planning Assessments. Under Reliability Standard TPL-001-4, the SOLs established for the planning horizon pursuant to the FAC-010 and FAC-014 Reliability Standards are not even referenced.

The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct where the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new FAC-015-1 Reliability Standard to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System steady-state voltage limits, and stability performance criteria used in their Planning Assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

- Clarity and efficiency of communication of limits and criteria between planning and operating entities is improved with FAC-015-1.

System Operating Limits in the Planning Horizon

There are two different time frames in which the System is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology, developed pursuant to FAC-010-3, is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the System could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the System (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission System. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that, if operated within, will result in reliable System operation. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their System. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the

System is being reliably operated. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the System during operations.

One of the key aspects of the SDT's proposed construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term "Operating" in System "Operating" Limits. The components of SOLs include the use of owner-provided Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use owner-provided Facility Ratings Facility owners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement R4 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those Systems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those Systems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different System conditions (different transfers, weather assumptions, load levels, etc.) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3, R5, R5.3, R5.4, R6, R6.1, and R6.2 reference the methodology and the Planning Coordinators role in establishing SOLs. Retirement of FAC-010-3 would consequently necessitate corresponding revisions of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is a methodology* in that it comprehensively and systematically outlines appropriate System performance and the necessary analysis,actions, and documentation requirements necessary in the reliable planning of the BES. This comprehensive methodology describes how the transmission System should be studied, addresses the establishment of performance criteria, prescribes the Contingencies that must be analyzed, and requires the determination of the corrective actions that should be taken to ensure future System reliability. Furthermore, TPL-001-4 exceeds System performance requirements identified in FAC-010-. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

<u>Modeling</u>:

TPL-001-4, Requirement R1 – "Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment."

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement R5 – "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."

TPL-001-4, Requirement R6 – "Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – "Steady State & Stability Performance Planning Events"

<u>Reporting</u>:

TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement R8 – "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

Corrective Action:

TPL-001-4, R2.7: "For the planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met."

Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as "Requirements Recommended for Retirement" in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC's P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that planners use limits and criteria in their Planning Assessments that are equally or more limiting than the limits and criteria established in accordance with the RC's SOL Methodology.

The Perceived "Gap"

The perceived "gap" stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-Facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the RC's SOL Methodology with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate "methodology" around limits and criteria is also removed.

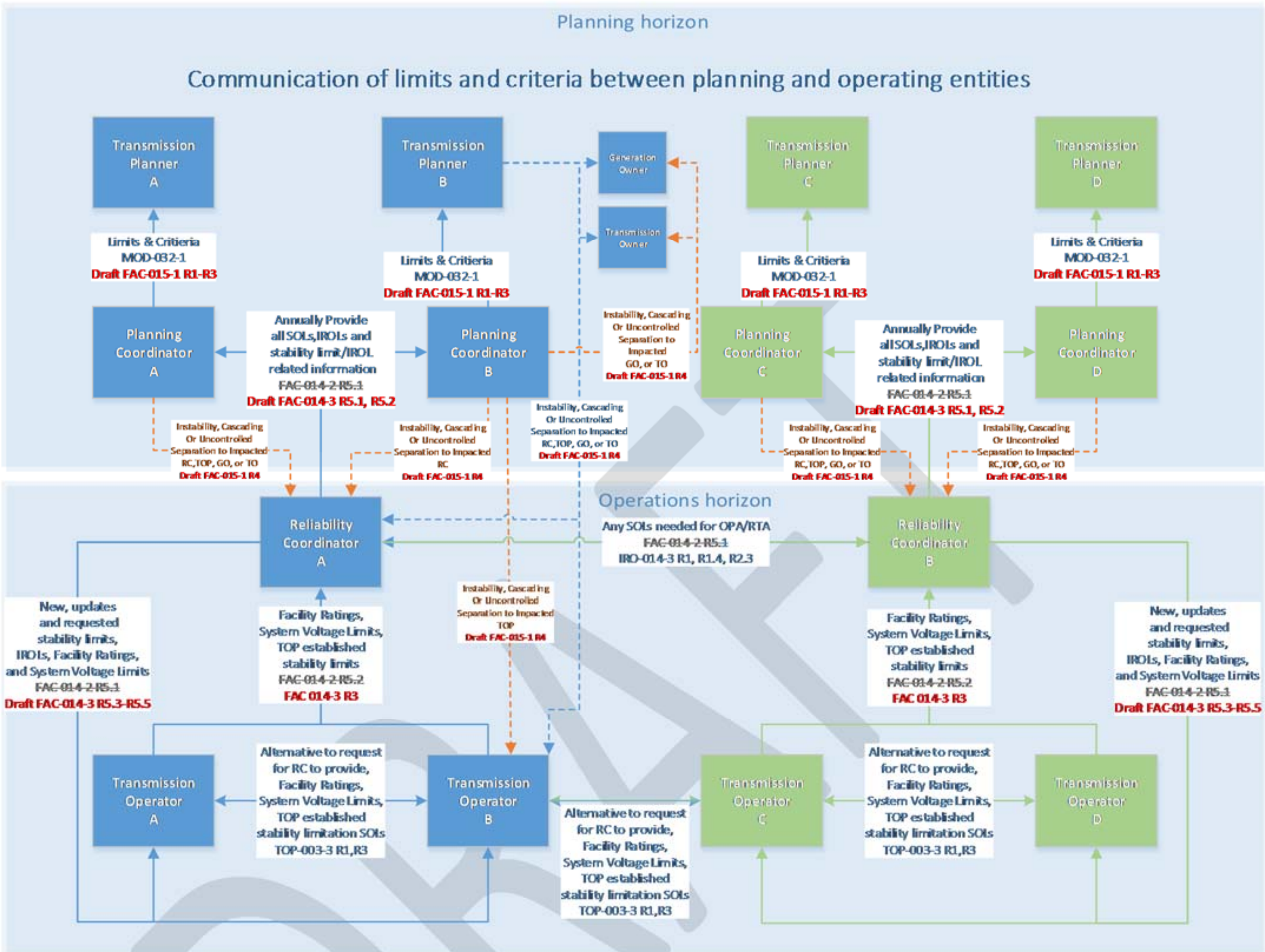
Development of FAC-015-1

Despite the comprehensive requirements in TPL-001-4, and to address the perceived gap, the SDT developed FAC-015-1 with the title "Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology" and the purpose "to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology." FAC-015-1 requires the PC and TP to implement processes that ensure the Facility Ratings, System steady-state voltage limits, and stability performance criteria used in its Planning Assessment are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC's SOL Methodology.

Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC's and TP's responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

The following figure shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.



FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2. The SDT's proposed construct takes into account that these requirements have been effectively replaced by TPL-001-4 and are now being improved upon by the proposed FAC-015-1. The communication of stability related information identified in FAC-014-2 Requirement R6, from the PC to the RC, is also retained through the communication of the annual Planning Assessment, as required by TPL-001, and the newly proposed FAC-015-1 Requirement R4. This relocation allows for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Rationales for FAC-010-3 (Retirement) and FAC-015-1

~~September~~ May 201~~7~~8

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning ~~Authority~~ Coordinator (PC) must have a documented methodology for establishing SOLs (including IROLs) within its PC Area ~~used in~~for the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires ~~Planning Coordinators (~~PCs~~)~~ and Transmission Planners (TPs) to establish and communicate SOLs and IROLs, used in the planning horizon, that are consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, ~~namely, those in~~such as the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically:

- ~~,~~ T~~t~~he retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4.~~,~~
- ~~a~~All of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3.
- ~~, and a~~All of the IRO standards have been modified.

The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address, in some manner, the foundational ~~reliability~~ concept of reliable S~~s~~ystem performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO Reliability ~~s~~Standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC Reliability S~~s~~tandards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC Reliability ~~s~~Standards by minimizing redundancy, allowing for better continuity ~~from~~ in the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable S~~s~~ystem performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a documented methodology for establishing SOLs for use in the planning horizon. Additionally, the SDT also proposes the retirement of the ~~, as well as the~~ corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs ~~were~~ was unnecessary and not useful for ensuring reliable planning or ~~reliable~~ Reliable ~~o~~Operation~~s~~. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. Supplementally, ~~T~~the SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

Under the current construct, PCs and RCs may have significantly different SOL Methodologies as the currently-effective Reliability Standards (FAC-010-3, FAC-011-3 & FAC-014-2) do not have any link requiring coordination between the methodologies. Furthermore, the nature of the current construct does not address continuity between planning and operations and may potentially result in a S~~s~~ystem not adequately planned for operational needs. The SDT's proposed changes help address the potential for inconsistencies between the PC's SOL Methodology and the RC's SOL Methodology.

Additionally, because of the evolution of the TPL standards, there are many redundancies in the responsibilities for PCs and ~~Transmission Planners (~~TPs~~)~~ between those in FAC-010/FAC-014 and those in TPL-001-4. In fact, planners are under no obligation to use ~~(and many do not use)~~ the PC's SOL Methodology for their Planning Assessments. Under Reliability Standard TPL-001-4, the SOLs established for the planning horizon pursuant to the FAC-010 and FAC-014 Reliability Standards are not even ~~necessary~~ referenced~~for reliable planning~~.

The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct~~. Under the proposed construct,~~ where the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new ~~standard~~ FAC-015-1 Reliability Standard to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System ~~(~~steady-state~~)~~ voltage limits, and stability performance criteria used in their

~~planning~~ Planning ~~A~~assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria ~~as determined~~established in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 ~~and proposed FAC-015-1~~ such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

- Clarity and efficiency of communication of limits and criteria between planning and operating entities is improved with FAC-015-1.

System Operating Limits in the Planning Horizon

There are two different time frames in which the ~~system~~ System is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology, developed pursuant to FAC-010-3, is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the ~~system~~ System could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the ~~system~~ System (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission ~~system~~System. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that, if operated within, will result in reliable~~the~~ ~~S~~system ~~being *operated* reliably~~operation. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their S~~s~~ystem. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the S~~s~~ystem is being reliably operated. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the S~~s~~ystem during operations.

One of the key aspects of the SDT's proposed ~~new~~ construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term "Operating" in System "Operating" Limits. The components of SOLs include the use of owner-provided Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use owner-provided Facility Ratings ~~provided by~~ Facility o~~O~~wners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement ~~R6~~ R4 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those S~~s~~ystems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those S~~s~~ystems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different S~~s~~ystem conditions (different transfers, weather assumptions, load levels, etc.) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3, R5, R5.3, ~~and~~ R5.4, R6, R6.1, and R6.2 reference the methodology and the Planning Coordinators role in establishing SOLs~~ require its use~~. Retirement of FAC-010-3 would consequently necessitate ~~retirement~~ corresponding revisions of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

~~The requirements in the TPL-001-4 standard require a comprehensive Planning Assessment and includes the establishment of limits and criteria (Facility ratings, System steady-state voltage limits, and stability performance criteria) and the *methodology* used by the planners (TPL-001-4, Requirement R6) to identify System instability (Cascading, voltage instability, or uncontrolled islanding) for the planning horizon. TPL-001-4 requires that a summary of the results of the assessment (TPL-001-4, Requirement R2) and a list of critical Contingencies that are expected to produce the most severe System impacts (TPL-001-4, Requirement R4.5) be included in the Planning Assessment. Further, TPL-001-4, Requirement R8 requires that the Planning Assessment, which includes all of information listed above, be distributed to any functional entity that has a reliability related need, for which the RC qualifies.~~

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is* a ~~*an established*~~ *methodology* in that it comprehensively and systematically outlines appropriate System performance and the necessary analysis,actions, and documentation requirements necessary~~used~~ in the reliable planning of the BES. This comprehensive methodology describes how the transmission S~~s~~ystem should be studied, addresses the establishment of performance criteria, prescribes the ~~outages~~ Contingencies that must be analyzed, ~~identifies the outages that do not meet the performance requirements,~~ and requires the determination of the corrective actions that should be taken to ensure future S~~s~~ystem reliability. Furthermore, TPL-001-4 ~~This established methodology meets and~~ exceeds System performance requirements identified in FAC-010~~-3 SOL methodology~~. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

Modeling:

TPL-001-4, Requirement R1 – "Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment."

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement R5 – "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."

TPL-001-4, Requirement R6 – "Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – "Steady State & Stability Performance Planning Events"

<u>Reporting</u>:

TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement R8 – "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

<u>Corrective Action</u>:

TPL-001-4, R2.7: "For the planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met."

Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as "Requirements Recommended for Retirement" in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC's P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that ~~the~~ planners use limits and criteria in their Planning Assessments that are ~~as~~ equally or more limiting~~, if not more limiting,~~ than the limits and criteria ~~developed~~ established in accordance with the RC's SOL Methodology.

The Perceived "Gap"

The perceived "gap" stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-~~facilities~~Facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the RC's SOL Methodology ~~in the operations horizon~~ with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate "methodology" around limits and criteria is also removed.

Development of FAC-015-1

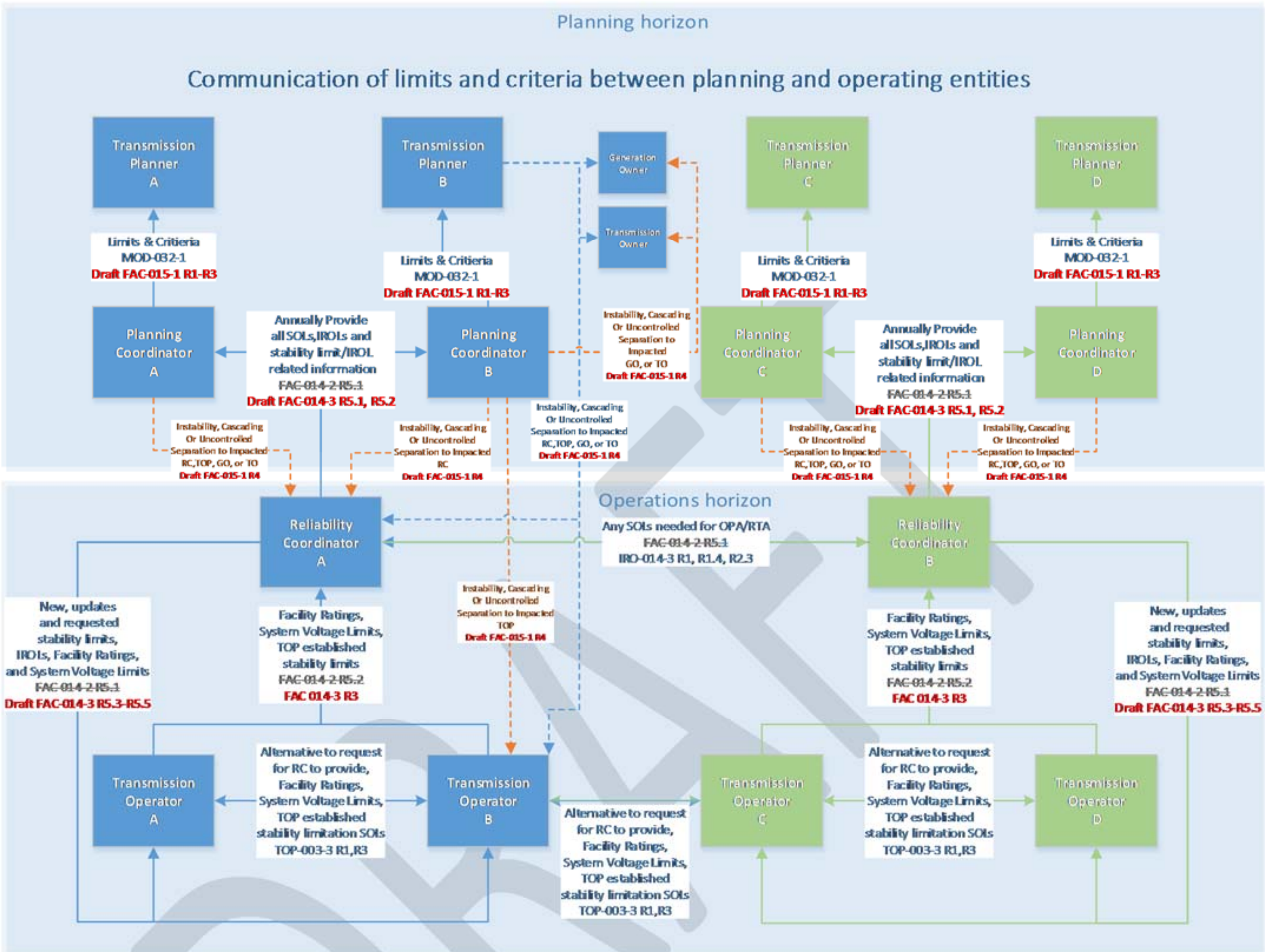
Despite the comprehensive requirements in TPL-001-4, and to address the perceived gap, the SDT developed FAC-015-1 with the title “Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology” and the purpose “to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator’s System Operating Limits (SOL) Methodology.” FAC-015-1 ~~will require~~requires the PC and ~~its~~ TP~~s~~ to implement processes that ensure ~~that~~ the Facility Ratings, System steady-state voltage limits, and stability performance criteria used in its ~~planning~~ Planning A~~a~~ssessment are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC’s SOL Methodology.

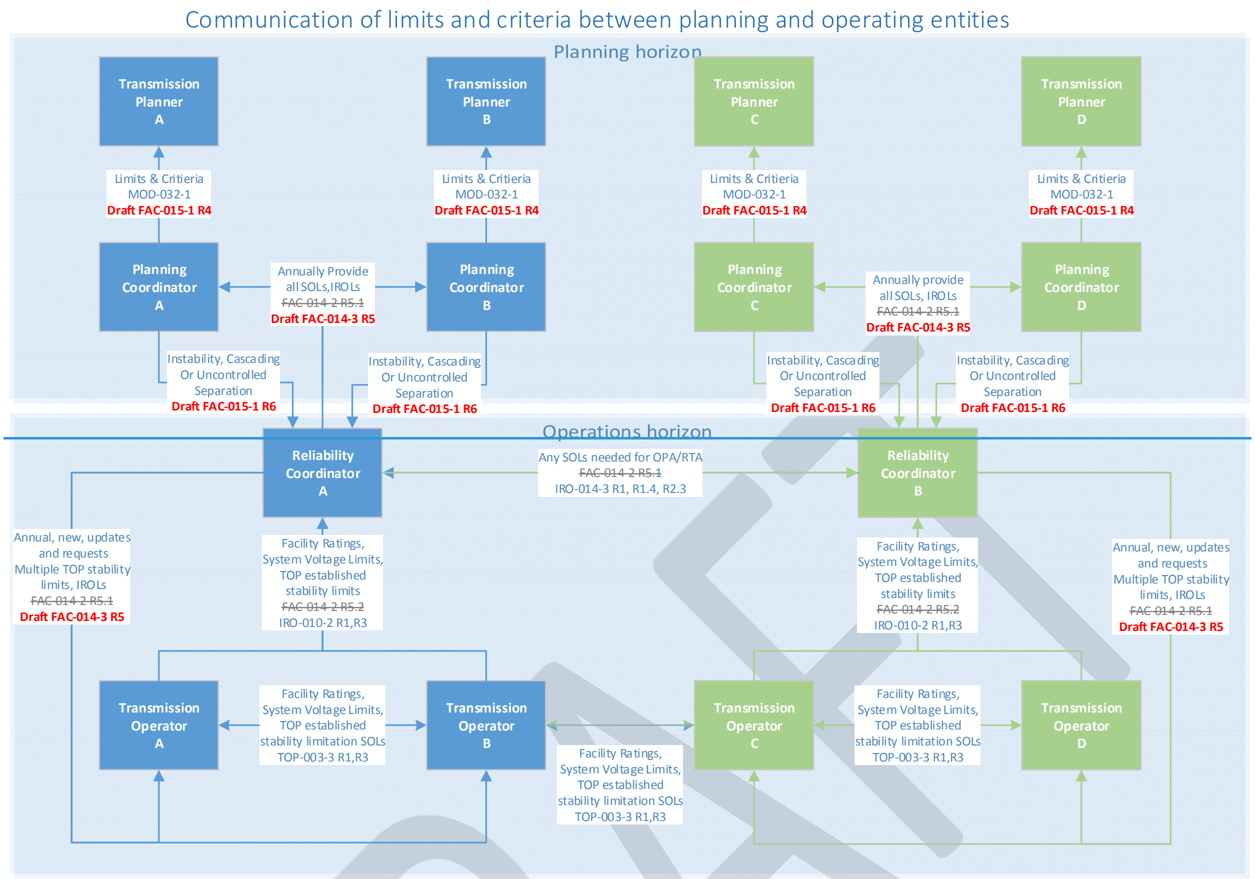
Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC’s and TP’s responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

~~The SDT is improving clarity and efficiency of communications by establishing a single point of contact between the RC and the PC for communication of SOLs from the operations horizon to the planning horizon. The PC, which is more familiar with and interacts regularly with TPs, is the entity responsible for communicating the SOLs to impacted Transmission Planners. This removes communications directly from the RC to the TPs and keeps the PC in the direct path of all SOLs from the operations time horizon. The requirements for FAC-015-1 can~~ thus ~~be thus met during times of annual preparation for its annual Planning Assessments.~~

The following figure ~~below~~ shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.


Planning horizon
Communication of limits and criteria between planning and operating entities
Transmission Planner A
Transmission Planner B
Transmission Planner C
Transmission Planner D
Generation Owner
Transmission Owner
Limits & Critieria
MOD-032-1
Draft FAC-015-1 R1-R3
Planning Coordinator A
Planning Coordinator B
Planning Coordinator C
Planning Coordinator D
Annually Provide all SOLs,IROLs and stability limit/IROL related information
FAC-014-2 R5.1
Draft FAC-014-3 R5.1, R5.2
Instability, Cascading Or Uncontrolled Separation to Impacted GO, or TO
Draft FAC-015-1 R4
Instability, Cascading Or Uncontrolled Separation to Impacted RC,TOP, GO, or TO
Draft FAC-015-1 R4
Instability, Cascading Or Uncontrolled Separation to Impacted RC
Draft FAC-015-1 R4
Operations horizon
Reliability Coordinator A
Reliability Coordinator B
Any SOLs needed for OPA/RTA
FAC-014-2 R5.1
IRO-014-3 R1, R1.4, R2.3
New, updates and requested stability limits, IROLs, Facility Ratings, and System Voltage Limits
FAC-014-2 R5.1
Draft FAC-014-3 R5.3-R5.5
Facility Ratings, System Voltage Limits, TOP established stability limits
FAC-014-2 R5.2
FAC 014-3 R3
Instability, Cascading Or Uncontrolled Separation to Impacted TOP
Draft FAC-015-1 R4
Transmission Operator A
Transmission Operator B
Transmission Operator C
Transmission Operator D
Alternative to request for RC to provide, Facility Ratings, System Voltage Limits, TOP established stability limitation SOLs
TOP-003-3 R1,R3



FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2.~~ With FAC-010-3 and FAC-014-2 Requirements R3, R4, R5.3 and R5.4~~. The SDT's proposed construct takes into account that these requirements have been ~~being~~ effectively replaced by TPL-001-4 and are now being improved upon by the proposed FAC-015-1~~,~~. T~~t~~he communication of stability related information identified in FAC-014-2 Requirement R6, from the PC to the RC, ~~remained~~is also retained through the communication of the annual Planning Assessment, as required by TPL-001, and the ~~. The SDT has opted to relocate the content addressed in FAC-014-2 Requirement R6 into~~ newly proposed FAC-015-1 Requirement ~~R6~~ R4~~rather than keep in FAC-014~~. This relocation allows~~ed~~ for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Rationale for FAC-011-4

August 2018

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires the SOL Methodology "be applicable for developing System Operating Limits (SOLs) used in the operations horizon." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires the SOL Methodology to "state that SOLs shall not exceed associated Facility Ratings." Facility Ratings to be used in operations as SOLs are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires the SOL Methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs." This language is preserved in Requirement R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between RCs and their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1. Require that BES bus/station have an associated System Voltage Limit, unless the Reliabilty Coordinators SOL Methodology specificall allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service relay settings for under voltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and provide the method for determining the common System Voltage Limits to be used in operations;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its RC Area for voltage-based Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of “System Voltage Limits”, both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identify the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are not set at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. unit stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of System damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, the SOL Methodology could describe which TOP or RC has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e.

winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the RC Area (including other RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation".

Requirement R5

R5. Each Reliability Coordinator shall identify in its SOL Methodology the Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study. The SOL Methodology shall:

5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-Time Assessments.

5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.

5.4. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement R4, to use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in the evaluation of post-Contingency state in OPAs and RTAs (thermal and voltage). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another’s internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. These Contingencies must be identified in the RC’s methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.3 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC’s methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R4 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria:

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its normal rating could be executed and completed within the specified time duration of those Emergency Ratings

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 and subparts R2.1 and R2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed FAC-014-3 Requirement R7 to support reliable operations for pre- and post-Contingency operating states. FAC-014-3 Requirement R7 states, *"Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances."*

FAC-011-4 Requirement R6, Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA pre-Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator has no time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow.

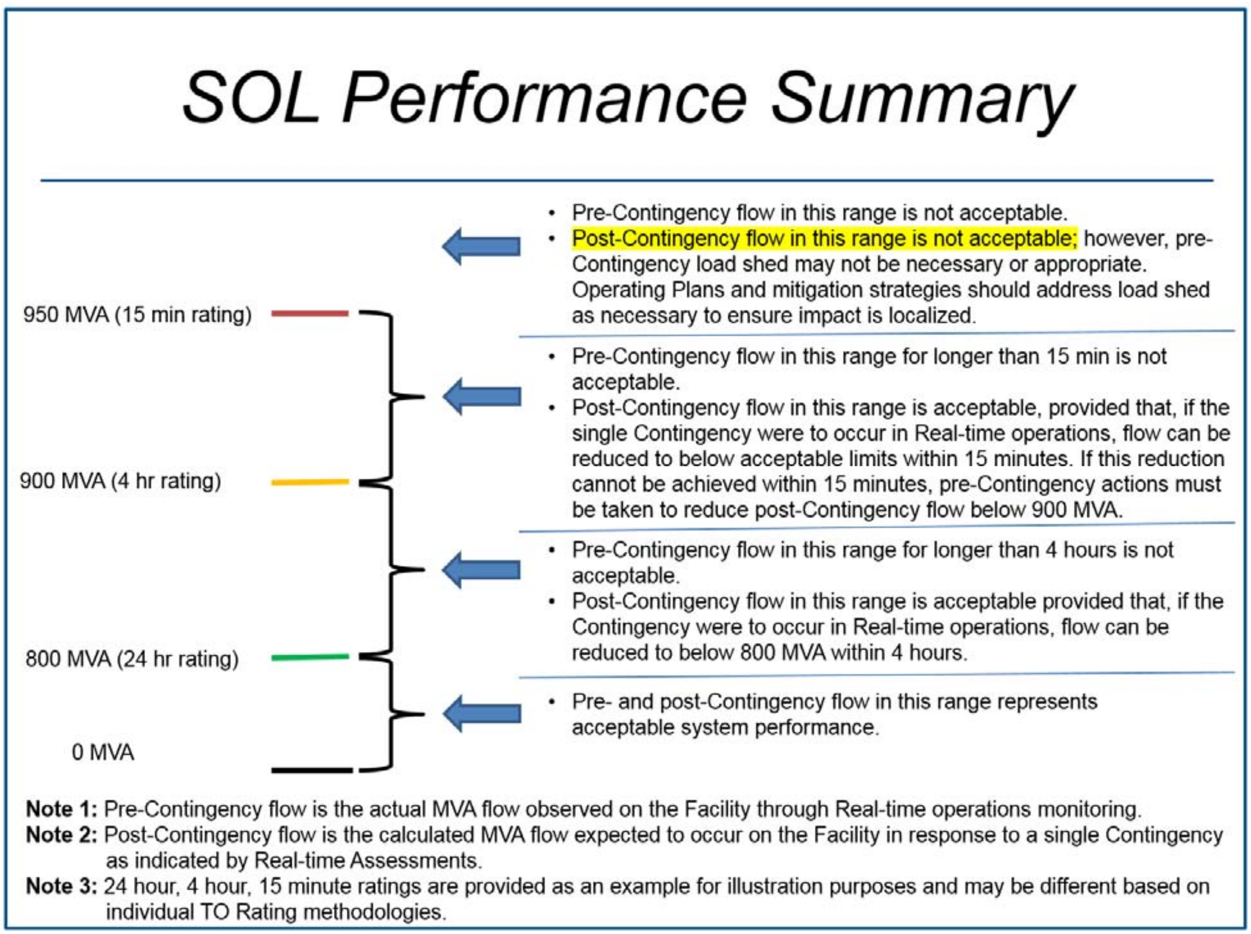


Figure 1 of the NERC SOL Whitepaper

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5, Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation.

Part 6.4 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5, Part 5.1.1 for establishing stability limits as identified in Requirement R5 Part 5.3. Per Requirement R6 Part 6.4, if any of these more severe Contingency events identified in R5 Part 5.3 were to occur, at a minimum the System is expected to remain stable. Part 6.4 was written in its own part to be very clear that these contingencies identified in R5 Part 5.3 are for the establishment of stability limits which may not be used in OPAs and RTAs. Typically, stability limits are established to prevent a Contingency (or set of specific Contingencies) from resulting in instability. Such stability limits are established such that if actual (pre-contingency) flow is kept under the stability limit, then any occurrence of the critical Contingencies would not result in instability. When these stability limits are used in OPAs and RTAs, they are monitored against actual (pre-contingent) flows. These stability limits do not need to be evaluated for the post-Contingency state in OPAs and RTAs (for example, through tools such as Real-time Contingency Analysis) because they already have the critical Contingencies built in to the limit itself.

Part 6.5 maintains the concept identified in FAC-011-3 R2.3.2 and intent of FERC Commission Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Requirement Part 6.5 clarifies that load shedding as a remedy in the operating plan should only be allowed after other options are exercised without regard for financial impact. The term "load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost
- Curtailment and adjustment of Interchange regardless of economic cost
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Requirement R7

R7. Each Reliability Coordinator shall include in its SOL Methodology:

7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Rationale R7

The two IROL related requirements in FAC-011-3 were preserved under Requirement R7.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator(s). The method shall address the periodicity for communicating established SOLs.

Rationale R8

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R8 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own TOP Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R9

R9. Each Reliability Coordinator shall provide its SOL Methodology to:

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Rationale R9

Requirement R9 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R9 Part 9.1 mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC's SOL Methodology.

In Requirement R9 Sub-part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Sub-part 9.2.2 also uses "responsible for planning" instead of "models any portion of" to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Sub-part 9.2.4 differs from Requirement R9 Sub-parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL Methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

Rationale for FAC-011-4

~~September 2017~~
July 2018

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing ~~SOL~~SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires ~~that~~ the SOL Methodology ~~shall~~ "be applicable for developing System Operating Limits (SOLs) used in the operations horizon~~.~~." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires ~~that~~ the SOL Methodology to "state that SOLs shall not exceed associated Facility Ratings~~.~~." Facility Ratings to be used in operations as ~~System Operating Limits (~~SOLs~~)~~ are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires ~~that~~ the SOL Methodology to "include a description of how to identify the subset of SOLs that qualify as ~~Interconnection Reliability Operating Limits (~~IROLs~~)~~.~~." This language is preserved in Requirement ~~R6~~R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ~~the applicable~~which owner-provided Facility Ratings are to be used in operations~~. The method shall address the use of common Facility Ratings between the Reliability Coordinator and~~ such that the Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure ~~that~~ the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining ~~the~~ Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between ~~the TOP~~RCs and ~~RC~~their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1. Require that BES ~~buses/stations~~ bus/station have an associated System Voltage Limit ~~except for~~, unless the ~~BES buses/stations that may be excluded as specified in the Reliability Coordinator's~~Reliabilty Coordinators SOL Methodology specificall allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect ~~the~~ voltage-based Facility ~~voltage~~ Ratings;

3.3. Require that System Voltage Limits are ~~higher~~greater than or equal to in-service ~~undervoltage~~relay settings for under voltage load shedding ~~(UVLS) relay settings~~systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the ~~Reliability Coordinator and the~~ Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~and provide the method for determining the common System Voltage Limits to be used in operations;

3.6. ~~Require~~Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. ~~Require~~Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within ~~a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas.~~each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its ~~Reliability Coordinator~~RC Area for ~~facility~~voltage-based ~~voltage limits~~Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage ~~limit~~Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 ~~identifies~~identify the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any voltage-based Facility ~~voltage~~ Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility ~~voltage~~ Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that ~~UVLS~~Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are not set ~~above all~~at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1 Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1 steady-state voltage stability;

4.1.2 transient voltage response;

4.1.3 ~~angular~~unit stability; and

4.1.4 System damping~~;~~.

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5~~;~~.

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area~~;~~.

4.4 Describe how ~~instability risks~~stability limits are ~~identified~~determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s~~),~~); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes ~~(RAS)~~ and other automatic post-Contingency mitigation actions~~[1]~~ in establishing stability limits used in operations.

4.4. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of ~~system~~System damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, ~~this requirement may be met~~

~~[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.~~

~~by providing language in~~ the SOL Methodology ~~describing~~could describe which TOP ~~(~~or ~~identifying that the~~ RC~~)~~ has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10~~%,~~ percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the ~~Reliability Coordinator~~RC Area (including other ~~Reliability Coordinator~~RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area ~~modeling~~ to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.~~6~~7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as ~~a~~measures of "last resort system preservation ~~measure~~".

Requirement R5

R5. Each Reliability Coordinator shall ~~include~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~Contingency events for use in determining stability limits and performing Operational Planning ~~Analyses~~Analysis (OPAs) and Real-time Assessments (RTAs~~).~~) for the area under study. The ~~method~~SOL Methodology shall ~~include~~:

5.1. ~~**5.1**~~ ~~The~~Specify the following ~~list of~~ single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. ~~**5.1.1**~~ Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with ~~normal clearing~~Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. ~~**5.2**~~ ~~Any~~Identify any additional single or multiple Contingency events or types of ~~single~~ Contingency events ~~identified~~for use in performing Operational Planning Analysis and Real-Time Assessments.

~~**5.2.**~~**5.3.** Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits~~, or for use in performing OPAs and RTAs.~~.

~~**5.3.** Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.~~

~~**5.3.**~~**5.4.** ~~**5.4**~~ ~~The~~Describe the method(s) for ~~considering~~identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement ~~R6~~R4, to ~~identify the Contingencies for~~ use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in ~~checking for all types~~the evaluation of

~~SOL exceedances~~ post-Contingency state in OPAs and RTAs (thermal~~,~~ and voltage ~~and stability limits~~). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. ~~The method for determining those~~These Contingencies must ~~also~~ be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.~~4~~3 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement ~~R6~~R4 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

R6. Each Reliability Coordinator shall include in its SOL Methodology, at a minimum, the following Bulk Electric System performance criteria:

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its normal rating could be executed and completed within the specified time duration of those Emergency Ratings

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 and subparts R2.1 and R2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed FAC-014-3 Requirement R7 to support reliable operations for pre- and post-Contingency operating states. FAC-014-3 Requirement R7 states, *"Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances."*

FAC-011-4 Requirement R6, Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA pre-Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator has no time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow.

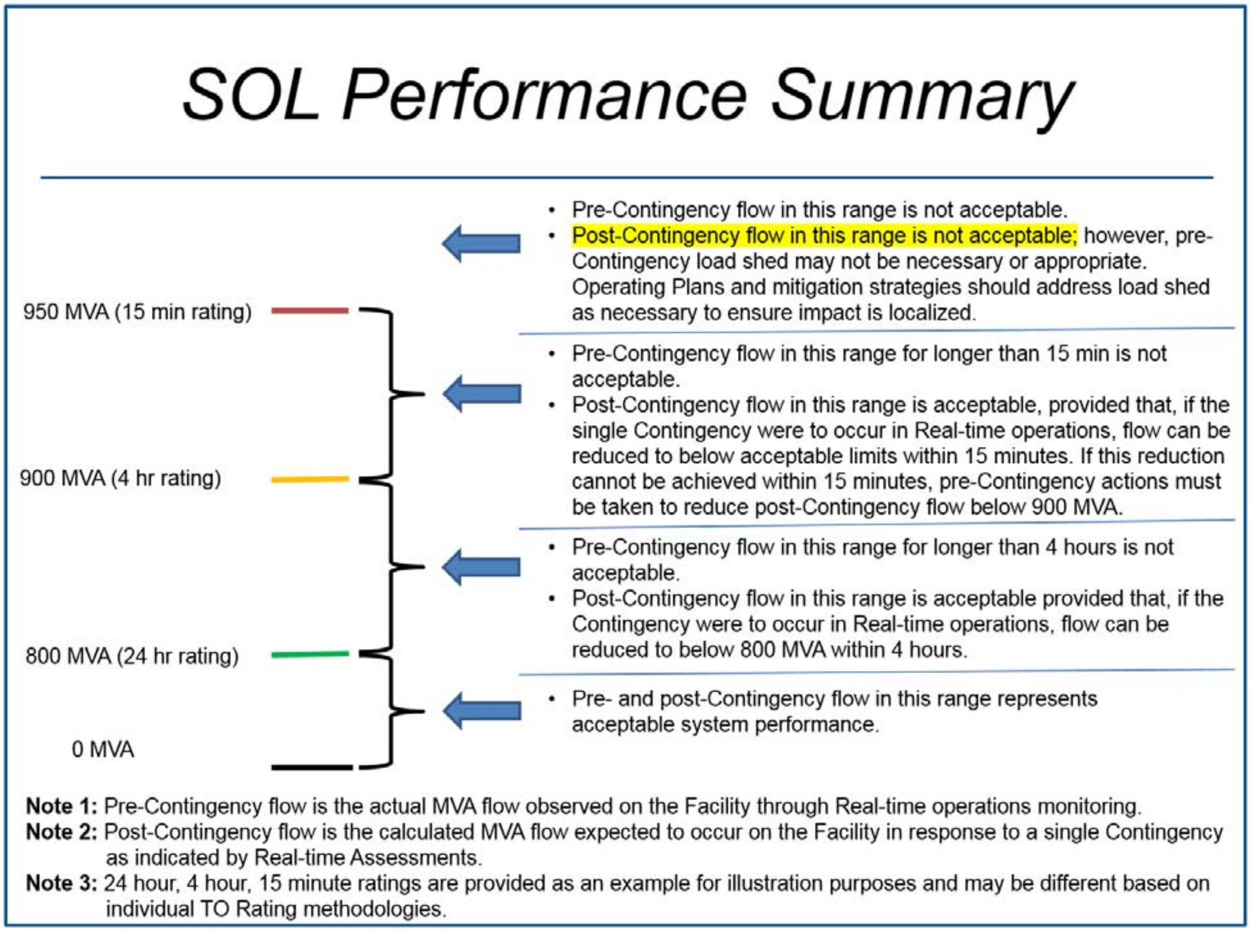


Figure 1 of the NERC SOL Whitepaper

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5, Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation.

Part 6.4 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5, Part 5.1.1 for establishing stability limits as identified in Requirement R5 Part 5.3. Per Requirement R6 Part 6.4, if any of these more severe Contingency events identified in R5 Part 5.3 were to occur, at a minimum the System is expected to remain stable. Part 6.4 was written in its own part to be very clear that these contingencies identified in R5 Part 5.3 are for the establishment of stability limits which may not be used in OPAs and RTAs. Typically, stability limits are established to prevent a Contingency (or set of specific Contingencies) from resulting in instability. Such stability limits are established such that if actual (pre-contingency) flow is kept under the stability limit, then any occurrence of the critical Contingencies would not result in instability. When these stability limits are used in OPAs and RTAs, they are monitored against actual (pre-contingent) flows. These stability limits do not need to be evaluated for the post-Contingency state in OPAs and RTAs (for example, through tools such as Real-time Contingency Analysis) because they already have the critical Contingencies built in to the limit itself.

Part 6.5 maintains the concept identified in FAC-011-3 R2.3.2 and intent of FERC Commission Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Requirement Part 6.5 clarifies that load shedding as a remedy in the operating plan should only be allowed after other options are exercised without regard for financial impact. The term "load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost
- Curtailment and adjustment of Interchange regardless of economic cost
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Requirement R7

~~R6.~~R7. Each Reliability Coordinator shall include in its SOL Methodology:

~~6.1.~~7.1. ~~6.1~~ A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs~~.~~).

~~6.2.~~7.2. ~~6.2~~ Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_v.

~~**Rationale R6**~~

~~The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.~~

~~Requirement R7~~

~~Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).~~

Rationale R7

The two IROL related requirements in FAC-011-3 were preserved under Requirement R7.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator(s). The method shall address the periodicity for communicating established SOLs.

Rationale R8

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement ~~R7~~R8 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own ~~Transmission Operator~~TOP Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement ~~R8~~R9

~~R7.~~R9. Each Reliability Coordinator shall provide its ~~new or revised~~ SOL Methodology to:

9.1. ~~8.1~~ Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request

9.2. Each of the following entities prior to the effective date of the SOL methodology:

~~7.1.1.~~9.2.1. Each adjacent Reliability Coordinator within ~~its~~the same Interconnection ~~prior to the effective date of the SOL Methodology~~;

~~7.1.2.~~9.2.2. ~~8.2~~ Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area ~~prior to the effective date of the SOL Methodology~~;

~~7.1.3.~~9.2.3. ~~8.3~~ Each Transmission Operator within its Reliability Coordinator Area ~~prior to the effective date of the SOL Methodology;~~; and

~~7.1.4.~~9.2.4. ~~8.4~~ Each ~~requesting~~ Reliability Coordinator that ~~indicates~~has requested to receive updates and indicated it had a reliability-related need ~~and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request~~.

~~Rationale R8~~

Rationale R9

Requirement ~~R8~~R9 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. ~~Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses "responsible for planning" instead of "models any portion of" to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it~~Requirement R9 Part 9.1 mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC's SOL Methodology.

In Requirement R9 Sub-part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Sub-part 9.2.2 also uses "responsible for planning" instead of "models any portion of" to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Sub-part 9.2.4 differs from Requirement R9 Sub-parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL Methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

Rationales for FAC-014-3

August 2018

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including IROLs, for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL Methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs.

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies);

5.2.5. A description of the associated system conditions; and

5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in

TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for limits and criteria to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle. In addition, it requires the RC to provide the impacted PCs the system conditions associated with the Stability Limit or IROL, for example: "summer peak", "winter peak", "high import" and etc.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a time frame designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Requirement R5 Parts 5.3 through 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each TOP and RC shall use the BES performance criteria specified in the RC's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances.

Rationale R6

The performance criteria specified in the RC's SOL methodology is discussed in more detail in the FAC-011-4 rationale document. It brings into the standard an updated version of the System performance criteria found in FAC-011-3 Requirement R2 by articulating the minimum expectations for System performance for the pre- and post-Contingency operating states. This, in essence, provides clarity for determining SOL exceedance when performing OPAs, RTAs and Real-Time monitoring in accordance with TOP and IRO standards.

FAC-014-3 Requirement R7 corresponds to FAC-011-4 Requirement R6, which requires each RC to include in its SOL Methodology, at a minimum, the BES performance criteria described in the subparts of Requirement R6. When TOPs and RCs implement FAC-014-3 Requirement R7, TOPs and RCs are by default using the minimum BES performance criteria stipulated in FAC-011-4 Requirement R6 and subparts when performing OPAs, RTAs, and Real-time monitoring.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationales for FAC-014-3

~~September 2017~~

August 2018

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including ~~Interconnection Reliability Operating Limits (IROLs),~~IROLs, for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a ~~Wide~~wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under ~~requirement~~Requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL ~~methodology~~Methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will ~~identify~~establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to ~~identify~~establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs.

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area~~,~~, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); ~~and,~~

~~5.2.5.~~ 5.2.5. A description of the associated system conditions; and

5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (~~TOP)s.~~TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause ~~of~~for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements~~ in~~ pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in

TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for ~~SOLs~~limits and criteria to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle. In addition, it requires the RC to provide the impacted PCs the system conditions associated with the Stability Limit or IROL, for example: "summer peak", "winter peak", "high import" and etc.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a ~~timeframe~~time frame designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. ~~Both~~ Requirement R5 Parts 5.~~4 and~~3 through 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

~~Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.~~

Each TOP and RC shall use the BES performance criteria specified in the RC's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances.

Rationale R6

~~Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:~~

> ~~*"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*~~

~~Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.~~

~~The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.~~

The performance criteria specified in the RC's SOL methodology is discussed in more detail in the FAC-011-4 rationale document. It brings into the standard an updated version of the System performance criteria found in FAC-011-3 Requirement R2 by articulating the minimum expectations for System performance for the pre- and post-Contingency operating states. This, in essence, provides clarity for determining SOL exceedance when performing OPAs, RTAs and Real-Time monitoring in accordance with TOP and IRO standards.

FAC-014-3 Requirement R7 corresponds to FAC-011-4 Requirement R6, which requires each RC to include in its SOL Methodology, at a minimum, the BES performance criteria described in the subparts of Requirement R6. When TOPs and RCs implement FAC-014-3 Requirement R7, TOPs and RCs are by default using the minimum BES performance criteria stipulated in FAC-011-4 Requirement R6 and subparts when performing OPAs, RTAs, and Real-time monitoring.

Rationale for FAC-015-1

August 2018

Requirement R1

Each Planning Coordinator (PC) and each of its Transmission Planners (TPs), when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's (RCs) System Operating Limit (SOL) Methodology. The process may allow the use of less limiting Facility Ratings if:

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan,
- Facility Rating differences are due to variations in ambient temperature assumptions,
- The PC provided a technical rationale for using a less limiting Facility Rating to each affected TP and RC, or
- The TP provided a technical rationale for using a less limiting Facility Rating to each affected PC and RC.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the RC's SOL Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and each of its TPs to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL Methodology. Requirement R1 explicitly allows for the following exceptions:

- The Facility has higher Facility Rating as a result of a planned upgrade, addition, or Corrective Action Plan,
- Facility Rating differences are due to variations in ambient temperature assumptions,
- The PC provided a technical rationale for using a less limiting Facility Rating to each affected TP and RC, or
- The TP provided a technical rationale for using a less limiting Facility Rating to each affected PC and RC.

It is not the SDT's intent to unduly burden planning entities with documentation requirements to justify or explain Facility Ratings that result from the implementation of Corrective Action Plans or the use of ambient temperature assumptions in seasonal planning models versus those assumptions used in operational analyses and monitoring in real time. However, the SDT's intent is to require that planning entities not use shorter duration Emergency Ratings than what the RC's SOL Methodology allows absent a documented rationale.

Requirement R2

Each PC and each of its TPs shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the RCs SOL Methodology. :

- The PC may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected TP and RC.
- The TP may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected PC and RC.

Rationale R2

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, PCs and TPs are required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC and each of its TPs to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs for planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting System steady state voltage limits than the System Voltage Limits established in accordance with the RC's SOL Methodology. Requirement R2 explicitly allows for the following exceptions:

- The PC provided a technical rationale for using a less limiting System steady-state voltage limit to each affected TP and RC.
- The TP provided a technical rationale for using a less limiting System steady-state voltage limit to each affected PC and RC.

Requirement R3

Each PC and each of its TPs shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the RC's SOL Methodology.

- The PC may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected TP and RC, or
- The TP may us less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected PC and RC.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RC's SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the RC's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC and each of its TPs to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. This does not give the RC authority over the PCs and TPs for planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning studies to utilize less limiting stability performance criteria than those established in accordance with the RC's SOL Methodology. Requirement R3 explicitly allows for the following exceptions:

- The PC provided a technical rationale for using a less limiting stability performance criterion to each affected TP and RC.
- The TP provided a technical rationale for using a less limiting stability performance criterion to each affected PC and RC.

Requirement R4

Each PC and each TP shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (PC only) to each impacted RC, Transmission Operator (TOP), Transmission Owner (TO) and Generator Owner (GO). This communication shall include:

4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

4.2 The associated stability criteria used as part of determining the instability;

4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;

4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;

4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R4

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R4. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in Requirement R4 is a key consideration for RCs and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R4 will supplement the severe System conditions identified in Requirement R4 Parts 4.4 and 4.5 of TPL-001-4.

Requirement R4 Part 4.3 also supports the proposed changes made in the CIP-002, CIP-014, and FAC-003 that require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation to the TO and GO. Of particular importance is the identification of Facilities that are elements of a Contingency event or are otherwise critical to the instability, Cascading, or uncontrolled separation. The TO or GO may consider those Facilities for higher levels of cyber protection, physical security, or vegetation management. The changes to CIP-002, CIP-014, and FAC-003 and the material discussed below uses the term "System instability" to clarify that the focus for the TO and GO is on Facilities that impact the BES, and not necessarily on a single generation unit instability. The applicable Facilities for cyber security, physical security, and vegetation management do not have to be the same.

Examples of Facilities that might be relevant to the TO and GO for higher levels of cyber protection, physical security, and vegetation management include:

- The Contingencies that result in System instability, Cascading, or uncontrolled separation
- A SVC that, if compromised, would result in a more severe System response to the Contingency event
- The line(s) identified as the first lost by Cascading

Examples of Facilities that may not be relevant to the TO and GO for higher levels of cyber protection, physical security, and vegetation management include:

- An individual generator that experiences unit instability
- All generators within the area impacted by System instability, Cascading, or uncontrolled separation
- All the lines that are impacted by Cascading
- A phase shifter that, while impacted by the event, does not significantly change the System's response to the event

Part 4.5 and Part 4.6 are intended to identify those measures that were employed in the planning studies to mitigate or prevent instability, Cascading, or uncontrolled separation. For example, a study might indicate that instability was avoided through the implementation of an operational measure, Remedial Action Scheme (RAS) or a UVLS. i.e., if the operational measure, RAS or the UVLS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent the instability, Cascading, or uncontrolled separation. Without this information, operators may be unaware of these risks and the measures required to address them.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-015-1

~~September 2017~~
August 2018

Requirement R1

Each Planning Coordinator~~,~~ (PC) and each of its Transmission Planners (TPs), when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than ~~those established~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's (RCs) System Operating Limit (SOL) Methodology. ~~If~~ The process may allow the ~~Planning Coordinator uses~~use of less limiting Facility Ratings ~~than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if:

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan,
- Facility Rating differences are due to variations in ambient temperature assumptions,
- The PC provided a technical rationale for using a less limiting Facility Rating to each affected TP and RC, or
- The TP provided a technical rationale for using a less limiting Facility Rating to each affected PC and RC.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the ~~Reliability Coordinator's (~~RC's~~) System Operating Limit (~~ SOL~~)~~ Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a ~~Planning Coordinator (~~PC~~)~~ area be coordinated between the PC and applicable ~~Transmission Planners (TPs).~~TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and each of its TPs to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. ~~If less limiting Facility Ratings are used by the PC, a technical justification~~ This is ~~required~~not intended to ~~be documented and provided to~~imply the RC~~. This does not give the RC~~ has authority over the ~~PC~~PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL Methodology. Requirement R1 explicitly allows for the following exceptions:

- The Facility has higher Facility Rating as a result of a planned upgrade, addition, or Corrective Action Plan,
- Facility Rating differences are due to variations in ambient temperature assumptions,
- The PC provided a technical rationale for using a less limiting Facility Rating to each affected TP and RC, or
- The TP provided a technical rationale for using a less limiting Facility Rating to each affected PC and RC.

It is not the SDT's intent to unduly burden planning entities with documentation requirements to justify or explain Facility Ratings that result from the implementation of Corrective Action Plans or the use of ambient temperature assumptions in seasonal planning models versus those assumptions used in operational analyses and monitoring in real time. However, the SDT's intent is to require that planning entities not use shorter duration Emergency Ratings than what the RC's SOL Methodology allows absent a documented rationale.

Requirement R2

Each ~~Planning Coordinator~~PC and each of its TPs shall implement a process to ensure that System steady~~-~~-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits ~~established~~used in ~~accordance with its Reliability Coordinator's~~operations per the RCs SOL Methodology. ~~If~~~~The process may allow the Planning Coordinator uses~~use of ~~less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if:

- The PC may use less limiting System steady state voltage limits if it provides~~d~~ a technical rationale for using a less limiting System steady-state voltage limit to each affected TP and RC.
- The TP may use less limiting System steady state voltage limits if it provides~~d~~ a technical rationale for using a less limiting System steady-state voltage limit to each affected PC and RC.

Rationale R2

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "Each ~~Transmission Planner and Planning Coordinator~~TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, ~~the PC is~~PCs and TPs are required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC and each of its TPs to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. ~~If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC.~~ This does not give the RC authority over the ~~PC~~PCs and TPs for planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting System steady state voltage limits than the System Voltage Limits established in accordance with the RC's SOL Methodology. Requirement R2 explicitly allows for the following exceptions:

- The PC provided a technical rationale for using a less limiting System steady-state voltage limit to each affected TP and RC.
- The TP provided a technical rationale for using a less limiting System steady-state voltage limit to each affected PC and RC.

Requirement R3

Each ~~Planning Coordinator~~PC and each of its TPs shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria ~~established~~used in ~~its Reliability Coordinator's~~operations per the RC's SOL ~~methodology. If the Planning Coordinator uses~~Methodology. ~~The process may allow the use of less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.~~if:

- The PC may use less limiting stability performance criteria if it provide~~s~~d a technical rationale for using a less limiting stability performance criterion to each affected TP and RC, or
- The TP may us less limiting stability performance criteria if it provide~~s~~d a technical rationale for using a less limiting stability performance criterion to each affected PC and RC.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the ~~RCs~~RC's SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the ~~Reliability Coordinator's~~RC's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When ~~the PC performs~~PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC and each of its TPs to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. ~~If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC.~~ This does not give the RC authority over the ~~PC~~PCs and TPs for planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning studies to utilize less limiting stability performance criteria than those established in accordance with the RC's SOL Methodology. Requirement R3 explicitly allows for the following exceptions:

- The PC provided a technical rationale for using a less limiting stability performance criterion to each affected TP and RC.
- The TP provided a technical rationale for using a less limiting stability performance criterion to each affected PC and RC.

Requirement R4

~~Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.~~

~~Requirement R5~~

~~Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.~~

~~Rationale R4 and R5~~

~~Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate~~

~~These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.~~

~~Requirement R6~~

~~Each Planning Coordinator~~Each PC and each TP shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (PC only) to each impacted ~~Reliability Coordinator and~~ RC, Transmission Operator~~.~~ (TOP), Transmission Owner (TO) and Generator Owner (GO). This communication shall include:

- ~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- ~~6~~4.2 The associated stability criteria used as part of determining the instability;
- ~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation;
- ~~6.4~~4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;
- 4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and
- 4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale ~~R6~~R4

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement ~~R6~~R4. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and ~~Transmission Operators (~~TOPs~~)~~.

The information itemized in Requirement ~~R6~~R4 is a key consideration for ~~RC~~RCs and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement ~~R6~~R4 will supplement the severe System conditions identified ~~Requirements~~in Requirement R4 Parts 4.4 ~~&~~and 4.5 of TPL-001-4.

Requirement R4 Part 4.3 also supports the proposed changes made in the CIP-002, CIP-014, and FAC-003 that require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation to the TO and GO. Of particular importance is the identification of Facilities that are elements of a Contingency event or are otherwise critical to the instability, Cascading, or uncontrolled separation. The TO or GO may consider those Facilities for higher levels of cyber protection, physical security, or vegetation management. The changes to CIP-002, CIP-014, and FAC-003 and the material discussed below uses the term "System instability" to clarify that the focus for the TO and GO is on Facilities that impact the BES, and not necessarily on a single generation unit instability. The applicable Facilities for cyber security, physical security, and vegetation management do not have to be the same.

Examples of Facilities that might be relevant to the TO and GO for higher levels of cyber protection, physical security, and vegetation management include:

- The Contingencies that result in System instability, Cascading, or uncontrolled separation
- A SVC that, if compromised, would result in a more severe System response to the Contingency event
- The line(s) identified as the first lost by Cascading

Examples of Facilities that may not be relevant to the TO and GO for higher levels of cyber protection, physical security, and vegetation management include:

- An individual generator that experiences unit instability
- All generators within the area impacted by System instability, Cascading, or uncontrolled separation
- All the lines that are impacted by Cascading
- A phase shifter that, while impacted by the event, does not significantly change the System's response to the event

Part 4.5 and Part 4.6 are intended to identify those measures that were employed in the planning studies to mitigate or prevent instability, Cascading, or uncontrolled separation. For example, a study might indicate that instability was avoided through the implementation of an operational measure, Remedial Action Scheme (RAS) or a UVLS. i.e., if the operational measure, RAS or the UVLS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent the instability, Cascading, or uncontrolled separation. Without this information, operators may be unaware of these risks and the measures required to address them.

	DBH Notes:	1st Pass. Looking in http:
	Pending future enforcement - Orange Rows	
Does the proposed SOL definition work in the context of this standard?	**Standard**	**Requirement ID**
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Guidelines & Tech. Basis
yes	CIP-002-5.1a	Attachment 1
yes	EOP-004-3	Attachment 1
yes	EOP-004-3	Attachment 2
yes	EOP-011-1	Attachment 1
yes	FAC-008-3	Purpose
yes	FAC-013-2	R1.2

yes	FAC-501-WECC-1	R.1.
yes	FAC-501-WECC-1	Attachment 1
yes	IRO-002-4	R3.
yes	IRO-002-4	Guidelines & Tech. Basis
yes	IRO-002-5	R5.
yes	IRO-006-5	Purpose
yes	IRO-006-EAST-2	Purpose

yes	IRO-006-EAST-2	R1.
yes	IRO-006-TRE-1	Purpose
yes	IRO-006-TRE-1	R1.
yes	IRO-006-TRE-1	R2.
yes	IRO-008-2	R1.
yes	IRO-008-2	R2.

yes	IRO-008-2	R5.
yes	IRO-008-2	R6.
yes	IRO-008-2	F. Associated Documents
yes	MOD-001-2	R1.1
yes	MOD-028-2	R6.1.

yes	MOD-029-2a	R3.
yes	MOD-030-3	R.2.4.
yes	PER-004-2	R2.
yes	PER-005-2	Guidelines & Tech. Basis
yes	PRC-002-2	R5., R5.1 & R5.1.2
yes	PRC-002-2	Guidelines for R5
yes	PRC-004-WECC-2	R2.3.2.2.

yes	PRC-010-2	Guidelines & Tech. Basis
yes	PRC-026-1	R1.

yes	PRC-026-1	Guidelines & Tech. Basis
yes	PRC-026-1	Guidelines & Tech. Basis
yes	TOP-001-3	R10.

yes	TOP-001-3	R14.
yes	TOP-001-3	R15.
yes	TOP-001-3	R18.
yes	TOP-001-3	Guidelines & Tech. Basis
yes	TOP-001-4	R10.
yes	TOP-001-4	R14

yes	TOP-001-4	R15
yes	TOP-001-4	R18.
yes	TOP-001-4	C. Compliance
yes	TOP-001-4	Guidelines & Tech. Basis
yes	TOP-002-4	R1.
yes	TOP-002-4	R2.

yes	TOP-002-4	Guidelines & Tech. Basis
yes	VAR-001-4.1	R1.
yes	VAR-001-4.1	Guidelines & Tech. Basis
yes	Burden	Glossary of Terms
yes	Constrained Facility	Glossary of Terms

yes	Interconnection Reliability Operating Limit	Glossary of Terms
yes	Operations Support Personnel	Glossary of Terms
yes	Total Flowgate Capability	Glossary of Terms

://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf for "system

Page(s)	Requirement Details
21	Bullet item under Managing Contstraints: Identify and monitor SOL’s & IROL’s (TOP, RC)
25	Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
28	Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
12	The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it’s possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
10 of 22	Event Type: IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) Threshold for Reporting: Operate outside the IROL for time greater than IROL Tv (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
12	There is a checkbox for IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)
12-13	See EOP-011-1 tab
1	A Facility Rating is essential for the determination of System Operating Limits.
1	A statement that the assessment shall respect known System Operating Limits (SOLs).

1	Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled “Major WECC Transfer Paths in the Bulk Electric System.”
4	1) A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System;”
1,2, 4	Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
8 (multiple)	See IRO-002-4 tab
2	Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
1	To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
1	To coordinate action between Reliability Coordinators within the Eastern Interconnection when implementing transmission loading relief procedures (TLR) for the Eastern Interconnection to prevent or manage potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).

1	Each Reliability Coordinator that initiates the Eastern Interconnection TLR procedure to prevent or mitigate an SOL or IROL exceedance shall identify the TLR level and the congestion management actions to be implemented, and shall update this information at least every clock hour (except TLR-1) after initiation up to and including the hour when the TLR level has been identified as TLR Level 0.[1]
1	To provide and execute transmission loading relief procedures that can be used to mitigate SOL or IROL exceedances for the purpose of maintaining reliable operation of the bulk electric system in the ERCOT Region.
1	The RC shall have procedures to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits (IROL) and System Operating Limits (SOL) that will not be resolved by the automatic actions of the ERCOT Nodal market operations system.
1	The RC shall act to identify and mitigate exceedances of identified Interconnection Reliability Operating Limits and System Operating Limits that will not be resolved by the automatic actions of the ERCOT Nodal market operations system, in accordance with the procedures required by R1.
1, 5	Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
1, 5	Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

2, 7-8	Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Realtime Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
2-3, 9-11	Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
12	various (Same exact language is found in the Associated Documents section of IR0-008-2, IRO-014-3, TOP-001-3, TOP-002-4) See Associated Docs tab.
2-3	Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state: 1.1.1 Facility ratings; 1.1.2 System voltage limits; 1.1.3 Transient stability limits; 1.1.4 Voltage stability limits; and 1.1.5 Other System Operating Limits (SOLs).
4	Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: - A System Operating Limit is reached on the Transmission Service Provider's system, or - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater[1].

3,6	Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.
3	Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
1	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.
12	Rationales for R5.
3	[R5.] Each Responsible Entity shall: [R5.1] Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: [R5.1.2] Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).
33	Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.
2-3	Transmission Operators shall adjust the SOL and operate the facilities within established limits.

29	Rationale for R8 - Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).
3	Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. [1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

16-17	R1 Criterion - The first criterion involves generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to the operating limit or RAS. A stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to an operating limit or RAS and do not terminate at the Transmission station associated with the generators that are subject to the SOL or RAS.
17	R1 Criterion - The second criterion involves Elements that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL. For example, if two long parallel 500 kV transmission lines have a combined SOL of 1,200 MW, and this limit is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.
4	Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

5	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
5	Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.
5-6	Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
7, 19	See TOP-001-3 tab
4-5	[R10.] Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:
5	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment

6	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
6	Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
9	Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.
24	See TOP-001-4 tab
1,4	Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
1,4	Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

10	See TOP-002-4 tab
2	Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
13	See VAR-001-4.1 tab
n/a	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
n/a	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.

n/a	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
n/a	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time operations of the Bulk Electric System.
n/a	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

operating"
Corresponding Measure
n/a
n/a
n/a
n/a
n/a
n/a
n/a
n/a
n/a

n/a

Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

n/a

n/a

n/a

n/a

The RC shall provide evidence including documentation of procedures to identify and mitigate exceedances of identified IROLs and SOLs to demonstrate compliance with Requirement R1.

To demonstrate compliance with Requirement R2, the RC shall provide evidence, such as system logs, voice recordings, or operating messages that shows that it acted to identify and to mitigate exceedances of IROLs and SOLs in accordance with the procedures required by R1.

n/a

Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A description of the method used to account for the limits specified in part 1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
o TFC or TTC being determined by one or more limits.
o Simulation being used to find the maximum TFC or TTC that remains within the limit.
o The application of a distribution factor in determining if a limit affects the TFC or TTC value.
o Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
o A statement that the monitoring of a select limit(s) results in the TFC or TTC not exceeding another set of limits.
o A statement that one or more of those limits are not applicable to the TFC or TTC determination.

n/a

Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path.

n/a

NONE

n/a

n/a

n/a

The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

n/a

Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

n/a

Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.
Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence

Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded
Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.
n/a
n/a

n/a

Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

n/a

n/a

n/a

n/a

n/a

n/a

n/a

n/a

http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

VSL	Needs to be Modified?
n/a	no
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
n/a	no
n/a	yes - clean up (not critical)
n/a	yes - clean up (not critical)
n/a	no
n/a	no
n/a	yes

n/a	yes - clean up (not critical)
	yes - clean up (not critical)
The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.	no
	no
The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.	no
n/a	no
n/a	no

n/a	no
n/a	no
The RC did not have procedures to identify and mitigate exceedances of identified IROLs and SOLs.	no
The RC failed to follow its procedures in identifying and mitigating an exceedance of an SOL.	no
The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).	no
The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the nextday provided by its Transmission Operators and Balancing Authorities.	no

Multiple levels	no
Multiple levels	no
	no
Multiple levels	no
n/a	no

n/a	no
n/a	no
[MULTIPLE LEVELS] Reliability Coordinator operating personnel did not place particular attention on X% or less of the SOLs or IROLs or inter-tie facility limits.	no
n/a	no
n/a	no
n/a	no
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within X hours but did perform the requirements within Y hours.	no

n/a	no
n/a	yes

	yes
	yes
n/a	no

The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment	no
The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.	no
The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.	no
n/a	no
n/a	no
The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment	no

The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.	no
The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.	no
n/a	no
n/a	no
The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).	no
The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.	no

n/a	no
References to SOLs is included in the VSLs for R2 and R3.	no
n/a	yes - clean up (not critical)
n/a	no
n/a	no

n/a	no
n/a	no
n/a	no

Modification Description
n/a
need to change the reference to the revised FAC standard and associated requirements
need to change the reference to the revised FAC standard and associated requirements
n/a
Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired on April 1. Not related to FAC SDT project.
Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired on April 1. Not related to FAC SDT project.
n/a
n/a
Needs to remove the reference to SOLs since this requirement is applicable to PCs. Revision could reference TPL performance table.

Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired o April 1. Not related to FAC SDT project.

Remove reference to Major WECC Path SOL violations. TOP-007-WECC-1 was retired o April 1. Not related to FAC SDT project.

n/a

n/a

n/a

n/a

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n/a

Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.

Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.
Address reference to SOLs identified by the PC's SOL Methodology. Also address reference to revised FAC-014 standard.
n/a

n/a

n/a

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n/a

n/a

n/a

Rationale references current SOL definition. Need to fix based on new definition.

n/a

n/a

n/a

n/a

n/a

Notes
Addressed by proposed modifications in CIP-002-6
Addressed by proposed modifications in CIP-002-6
IF a Facility Rating is an SOL, then by default, it is essential for determining SOLs. This statement is not necessary in the purpose of FAC-008, but it does no harm.
Addressed by proposed modifications in FAC-013-3

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

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BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
While the proposed definition of SOL dos not allow for "Other SOLs" as listed in R1.1.5, this requirement does not cause a problem. It will just never be used.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

Addressed by proposed modifications in PRC-026-2

Addressed by proposed modifications in PRC-026-2
Addressed by proposed modifications in PRC-026-2
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.
The term "Burden" is used once in the body of Reliability Standards. BAL-005-0.2b requirement R3 states, *"A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas."* This standard has been replaced by BAL-005-1 which is pending regulatory approval.
The term "Constrained Facility" is not used in the current body of Reliability Standards

BES performance criteria specified in FAC-011-4 Requirement R6 correlates to SOL exceedance through FAC-014-3 Requirement R7.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: "…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific **SOL** or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific **SOL** or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible **SOL** or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those **SOLs** or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day **SOL** or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Compliance/Data Retention
Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL Tv as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

TOP-001-3 also contains the same write-up as seen in the Associated Docs tab

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by **SOLs** for clarity and specificity. **SOLs** include voltage, Stability, and thermal limits and are thus the most limiting factor.

Includes the same occurrences as TOP-001-3 plus the one below

Rationale for Requirement R10:
New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.
The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.
The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances.
Examples include:

• OPA;
• Real-time Assessments (RTA);
• Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
• Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.
The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of **SOLs** in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.
TOP-002-4 also contains the same write-up as seen in the Associated Docs tab

Rationale for R1:
Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:
Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:
Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:

The approved definition of SOL as defined in the NERC Glossary of Terms is:

> *The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
> - *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
> - *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
> - *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The concept of SOL determination is not complete without looking at the associated NERC FAC standards approved FAC-008-3, proposed FAC-011-4, and proposed FAC-014-3:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Ratings Methodology and to establish Facility Ratings consistent with that methodology that respects the most limiting applicable

Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed are required to include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal Rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Emergency Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of proposed FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:

    a. Requirement R2 requires that the Reliability Coordinator's SOL Methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

    b. Requirement R3 requires that the Reliability Coordinator's SOL Methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.

    c. Requirement R4 requires that the Reliability Coordinator's SOL Methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements. Part 4.5 requires that the RC's SOL Methodology describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

3. Proposed FAC-011-4 requirement R6 contains the performance criteria for BES operations. Specifically, requirement R6 requires the Reliability Coordinator's SOL Methodology to include, at a minimum, the following Bulk Electric System performance criteria:

    a. Part 6.1: The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

        i. Part 6.1.1: Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings.

ii. Part 6.2.1: Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits.

iii. Part 6.1.3: Instability, Cascading, or uncontrolled separation do not occur.

b. Part 6.2: The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

i. Part 6.2.1: Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

ii. Part 6.2.2: Voltages are within emergency System Voltage Limits.

iii. Part 6.2.3: Instability, Cascading, or uncontrolled separation do not occur.

c. Part 6.3: The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

d. Part 6.4: The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

e. Part 6.5: In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

4. Proposed FAC-014-3, Requirement R2 requires that Transmission Operators to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

5. Proposed FAC-014-3, Requirement R7 requires Transmission Operators and Reliability Coordinators to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances. These performance criteria are reflected in proposed FAC-011-4 requirement R6 (above).

6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all Facilities that can

adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into operations studies.

Some have interpreted the language in previous versions of FAC-011 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in FAC-011, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in FAC-011 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within FAC-011, which is both:

1. To know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. To ensure that they are all observed in assessments of both the pre- and post-Contingency state when performing Operational Planning Analyses (OPA), Real-time Assessments (RTA), and Real-time monitoring.

It is important to understand the intent behind the language "the pre- and post-contingency state." The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability limits for the pre- and post-Contingency state. In Real-time operations, any of these types of limits can be the most restrictive limit at any point in time in the pre- or post-Contingency state. For example, if an area or Facility of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, a primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability limits for the pre- and post-Contingency state. How an entity accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **System Voltage Limits:**
   In the pre-Contingency state, operate within normal System Voltage Limits. In the post-Contingency state, operate within applicable emergency System Voltage Limits.
3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC's SOL Methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage response, unit stability, and System damping. Part 4.2 requires stability limits to be established to meet this prescribed stability performance criteria. For example, a study might

indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

Transient Stability Limits:
Transmission Operators establish transient stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

Voltage Stability Limits:
Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the proposed FAC and approved TOP standards, as well as the use of defined terms contained within those standards such as OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe acceptable system performance criteria for the pre- and post-Contingency state (proposed FAC-011-4 requirement R6).
2. TOP-001-3, Requirement R13 requires that each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. The System Operator’s goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

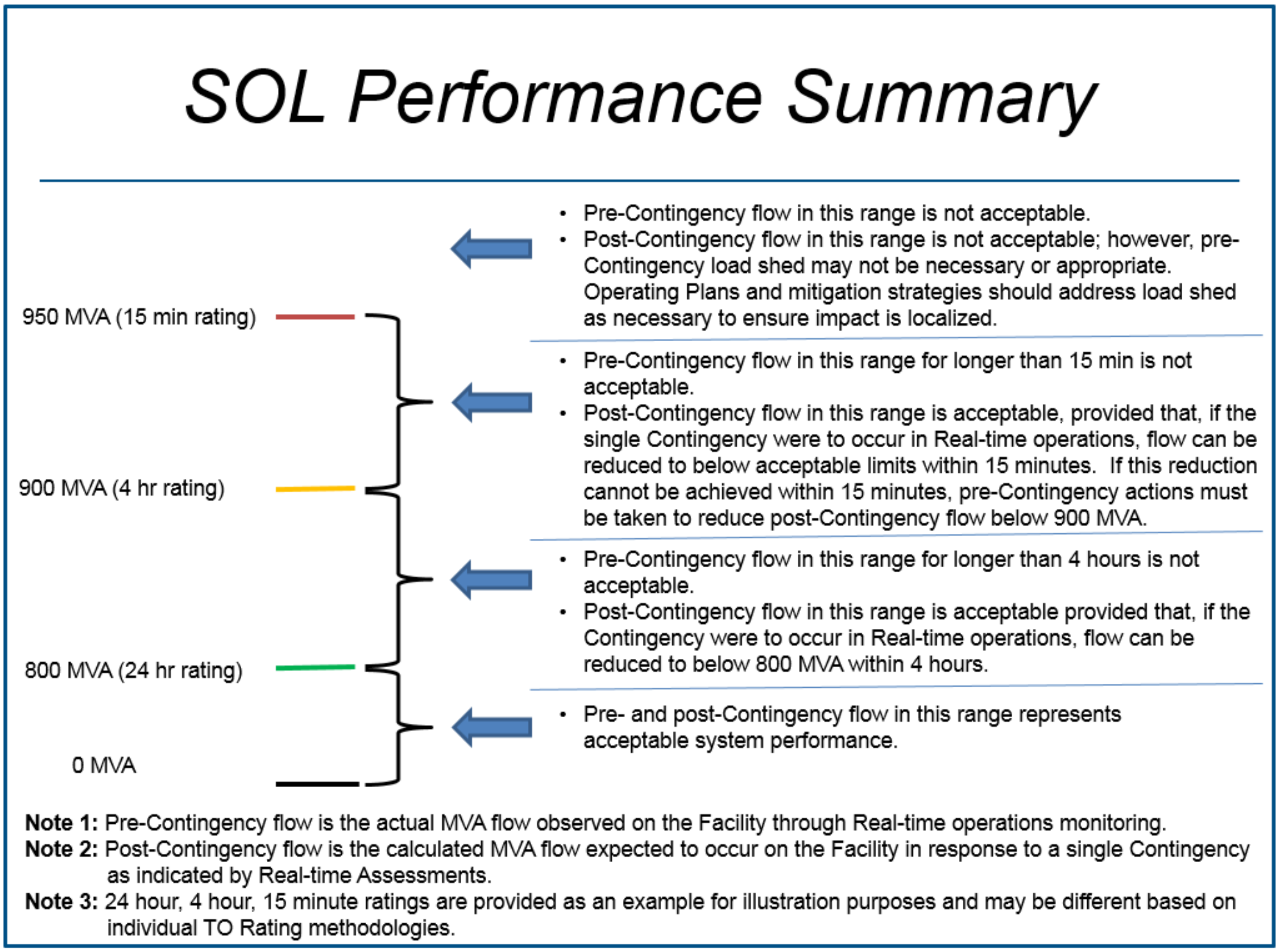

Figure 1. Facility Rating System Operating Limit Performance Summary

The following example scenarios describe appropriate operator action with respect to Figure 1:

1. **Example 1 Scenario** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) Is it important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating.

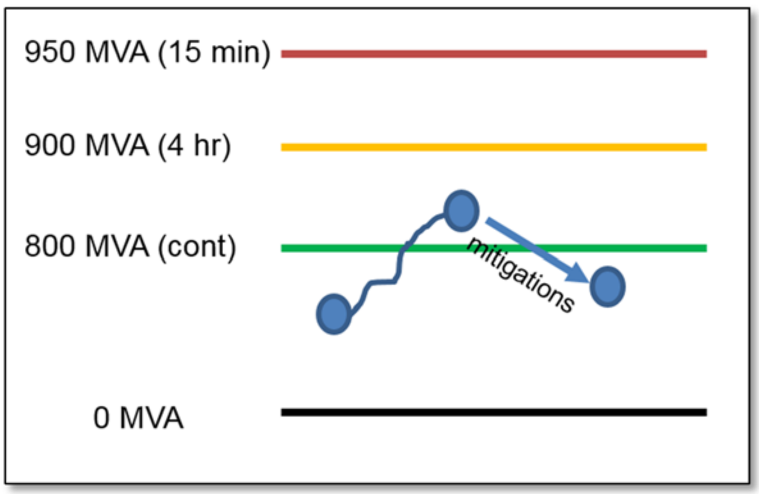

Figure 2. Example 1 Scenario – Pre-Contingency State

2. **<u>Example 2 Scenario</u>** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 stable.

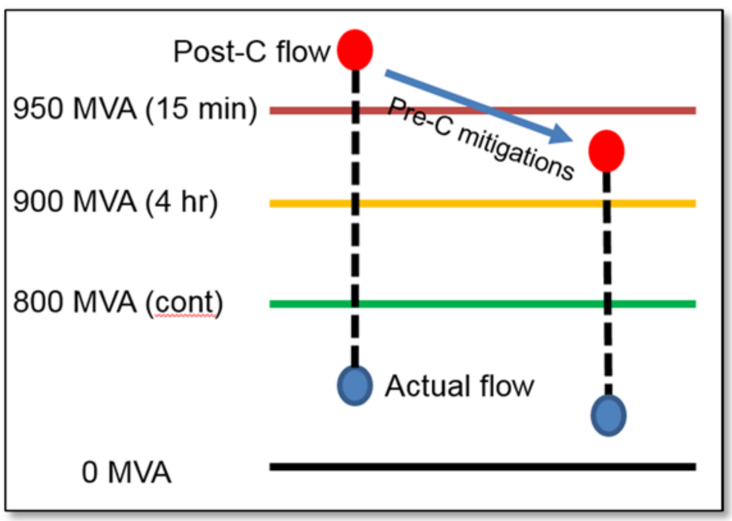

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **<u>Example 3 Scenario</u>** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending on how the line is rated based on the Transmission Owner's Facility Ratings Methodology. If this

information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

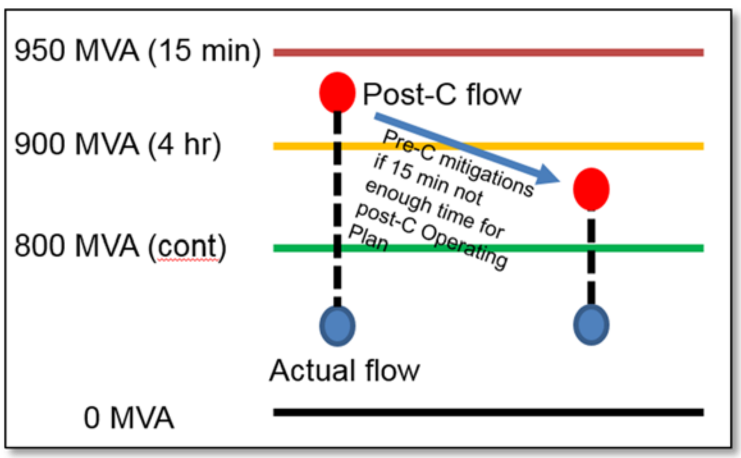

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **<u>Example 4 Scenario</u>** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would

immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

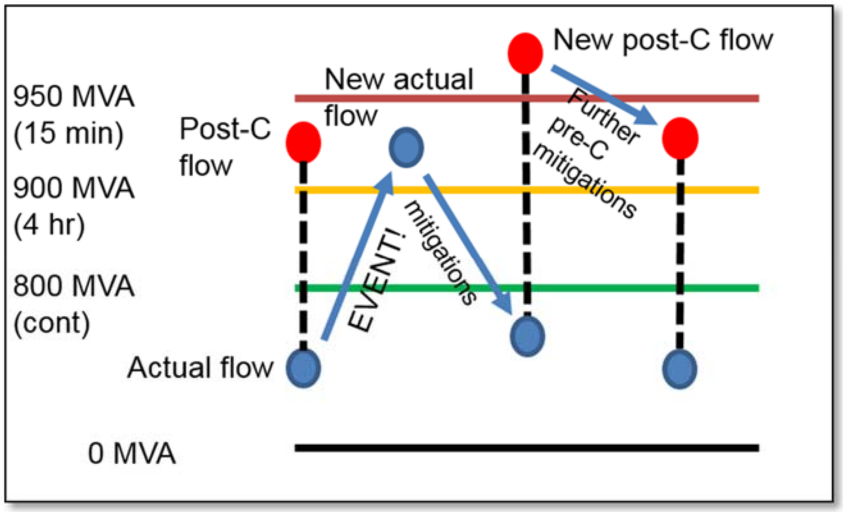

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

__Steady State Voltage Limit Exceedance__

SOL performance for System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency System Voltage Limits are required to be established by the TOP in accordance with the RC's SOL Methodology. FAC-011-4 Requirement R3 requires that the RC's SOL Methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3.

Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are applicable for the post-Contingency state. SOL exceedance with respect to these System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL Methodology. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within System Voltage Limits pre- or post-Contingency.

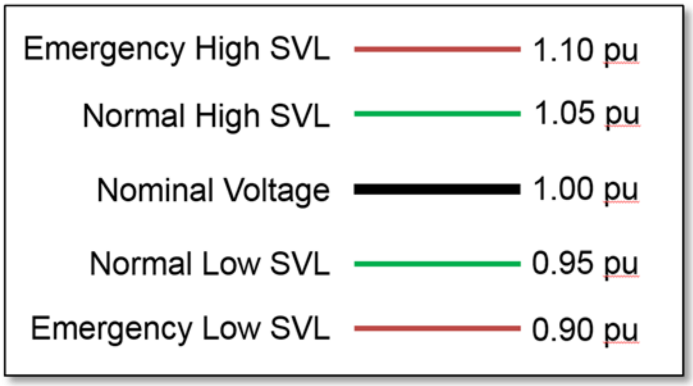

Figure 6. Example of a System Voltage Limit Set

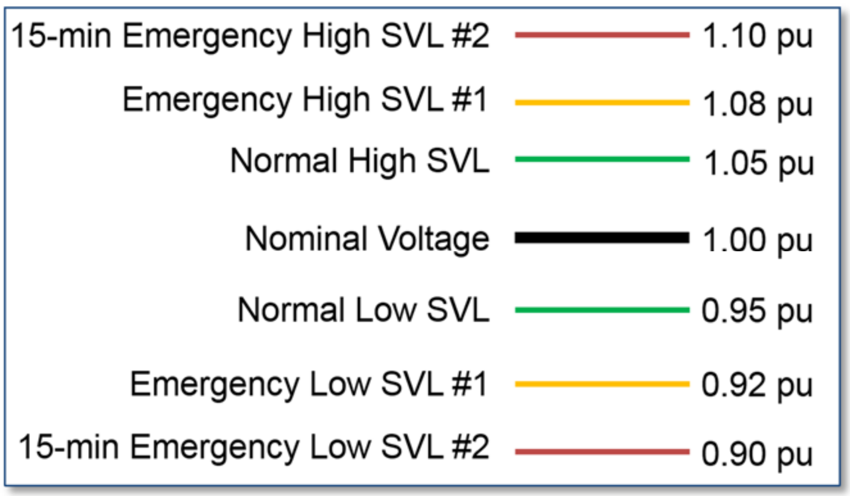

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

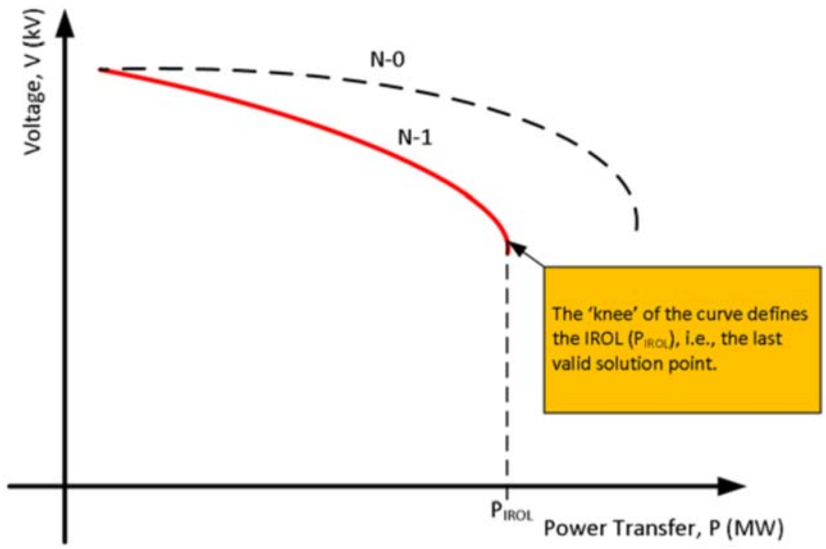

Figure 8. Voltage Stability System Operating Limit Performance Summary

SOL Exceedance and Operating Plans:

SOL exceedance occurs when the performance criteria as described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedance is determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedance is determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedance is identified through the evaluation of the actual state (or pre-Contingency state) and through an evaluation of Contingencies against that state. For stability limits, SOL exceedance is identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the

Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per proposed FAC-011-4, Requirement R6, preventing SOL exceedances from escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Use available effective actions and emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**
Emergency (15 min)	**All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.**

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts, generation output levels, Interchange, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Facility Ratings, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

> Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

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System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the ~~Standard Drafting Team's~~standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:

~~As stated~~

The approved definition of SOL as defined in the NERC Glossary of Terms ~~*Used in Reliability Standards, a SOL*~~ is:

> *The ~~defined as the~~ value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
> - *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
> - *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
> - *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The concept of SOL determination is not complete without looking at the ~~approved~~associated NERC FAC standards approved FAC-008-3, proposed FAC-011-~~2~~4, and proposed FAC-014-~~2~~3:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. ~~A Facility Rating is essential for the determination of SOLs.~~ The standard requires both Generation Owners and Transmission Owners

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2. The purpose of ~~approved~~proposed FAC-011-~~2~~4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. ~~Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:~~
~~**Pre-Contingency**: Acceptable system performance for the pre-Contingency state is characterized by the following:~~
Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:
   a. ~~The BES shall demonstrate transient, dynamic, and voltage Stability.~~Requirement R2 requires that the Reliability Coordinator's SOL Methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.
   b. Requirement R3 requires that the Reliability Coordinator's SOL Methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.
   c. Requirement R4 requires that the Reliability Coordinator's SOL Methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements. Part 4.5 requires that the RC's SOL Methodology describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

3. Proposed FAC-011-4 requirement R6 contains the performance criteria for BES operations. Specifically, requirement R6 requires the Reliability Coordinator's SOL Methodology to include, at a minimum, the following Bulk Electric System performance criteria:

Part 6.1: The actual
~~*All* Facilities shall be within their applicable Facility Ratings and thermal limits.~~
~~All Facilities shall be within their~~ pre-Contingency ~~voltage limits.~~

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~~All Facilities shall be within their Stability limits.~~

a. ~~Post~~state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency~~:~~ ~~Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):~~ state (Operational Planning Analysis) demonstrates the following:

Part 6.1.1: Flow through

~~*The* BES shall demonstrate transient, dynamic, and voltage Stability.~~

~~All~~ Facilities ~~shall be~~are within ~~their applicable Facility~~ Normal Ratings ~~and thermal limits.~~

~~All Facilities shall be~~ ; however, Emergency Ratings may be used only when System adjustments to return the flow within ~~their post-Contingency voltage limits.~~

i. ~~All Facilities shall be~~ its Normal Rating can be executed and completed within ~~their Stability limits~~the specified time duration of those Emergency Ratings.

ii. Part 6.2.1: Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits.

iii. Part 6.1.3: Instability, Cascading, or uncontrolled separation ~~shall~~do not occur.

b. ~~Approved~~Part 6.2: The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

i. Part 6.2.1: Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

ii. Part 6.2.2: Voltages are within emergency System Voltage Limits.

iii. Part 6.2.3: Instability, Cascading, or uncontrolled separation do not occur.

c. Part 6.3: The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

d. Part 6.4: The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

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e. Part 6.5: In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

~~2.~~4. Proposed FAC-014-~~2~~3, Requirement R2 requires that Transmission Operators to establish SOLs for ~~their~~its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology.

5. ~~Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2~~Proposed FAC-014-3, Requirement R7 requires Transmission Operators and Reliability Coordinators to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances. These performance criteria are reflected in proposed FAC-011-4 requirement R6 (above).

~~3.~~6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all ~~facilities~~Facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into ~~planning and~~ operations studies.

Some have interpreted the language in ~~approved~~previous versions of FAC-011~~-2, Requirement R2~~ to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in ~~approved~~ FAC-011~~-2, Requirement R2 sub-requirements~~, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in ~~approved~~ FAC-011~~-2, Requirement R2~~ will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within ~~approved~~ FAC-011~~-2~~, which is both:

1. ~~Know~~To know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. ~~Ensure~~To ensure that they are all observed in assessments of both the pre- and post-Contingency state ~~by~~when performing ~~a~~ Operational Planning Analyses (OPA), Real-time ~~Assessment~~Assessments (RTA), and Real-time monitoring.

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~~SOLs~~
It is important to understand the intent behind the language "the pre- and post-contingency state." The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on ~~Normal and Emergency (short-term)~~simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability limits~~, transient Stability~~ for the pre- and post-Contingency state. In Real-time operations, any of these types of limits~~, and voltage Stability limits – any of which~~ can be the most restrictive limit at any point in time in the pre- or post-Contingency~~-~~ state. For example, if an area or Facility of the BES is at no risk of encroaching upon ~~Stability~~stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the ~~voltage limits~~System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, ~~the SOL~~a primary focus of System Operators is ~~based on the actual set of~~ to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability limits~~, or Stability limits that are to be monitored~~ for the pre- and post-Contingency state. How an entity ~~remains within these SOLs~~accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line

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outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure ~~an SOL is not exceeded~~reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **System Voltage Limits:**
   In the pre-Contingency state, operate within normal ~~voltage limits.~~ System Voltage Limits. In the post-Contingency state, operate within applicable emergency System Voltage Limits.
3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC's SOL Methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage ~~limits.~~ response, unit stability, and System damping. Part 4.2 requires stability limits to be established to meet this prescribed stability performance criteria. For example, a study might indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

   Transient Stability Limits:
   Transmission Operators establish ~~SOLs~~transient stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

   Voltage Stability Limits:

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Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. ~~-~~Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. ~~-~~Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the ~~approved~~proposed FAC and ~~proposed~~approved TOP standards, as well as the use of defined terms contained within those standards such as ~~Operational Planning Analysis, Real-time Assessment~~OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. ~~Approved~~ FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe acceptable system performance criteria for the pre- and post-Contingency state~~.~~ (proposed FAC-011-4 requirement R6).
2. ~~Proposed~~ TOP-001-3, Requirement R13 requires that ~~a~~each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. ~~Proposed~~ TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. ~~Proposed~~ TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. ~~Figure 1 illustrates an SOL Performance Summary for Facility Ratings.~~The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has

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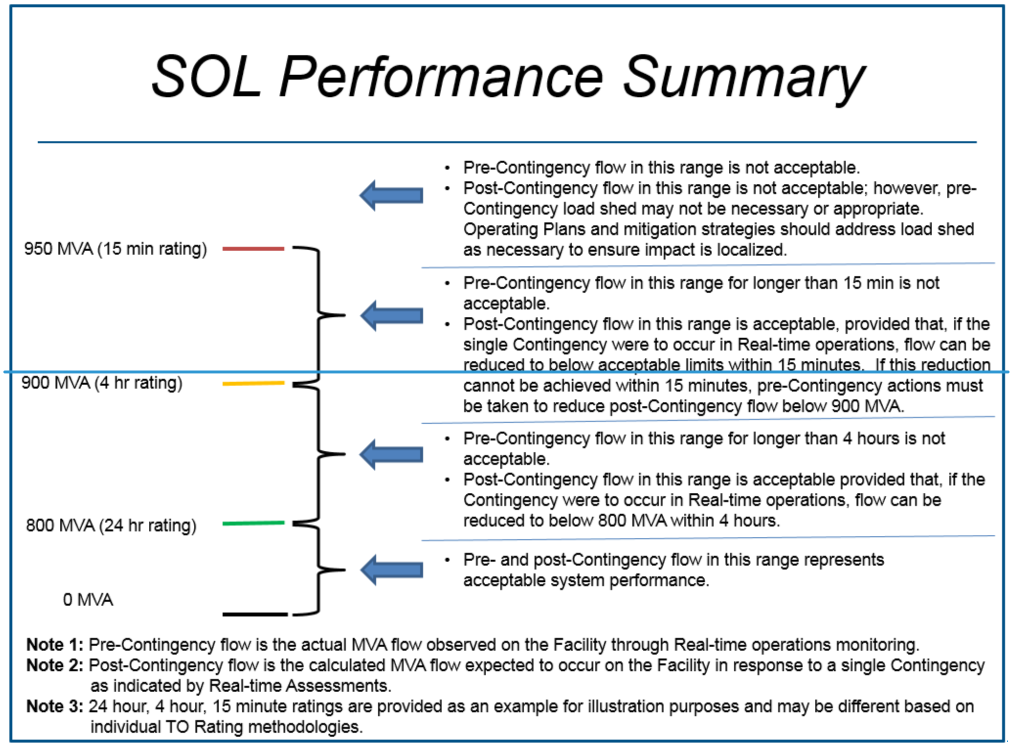
been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.



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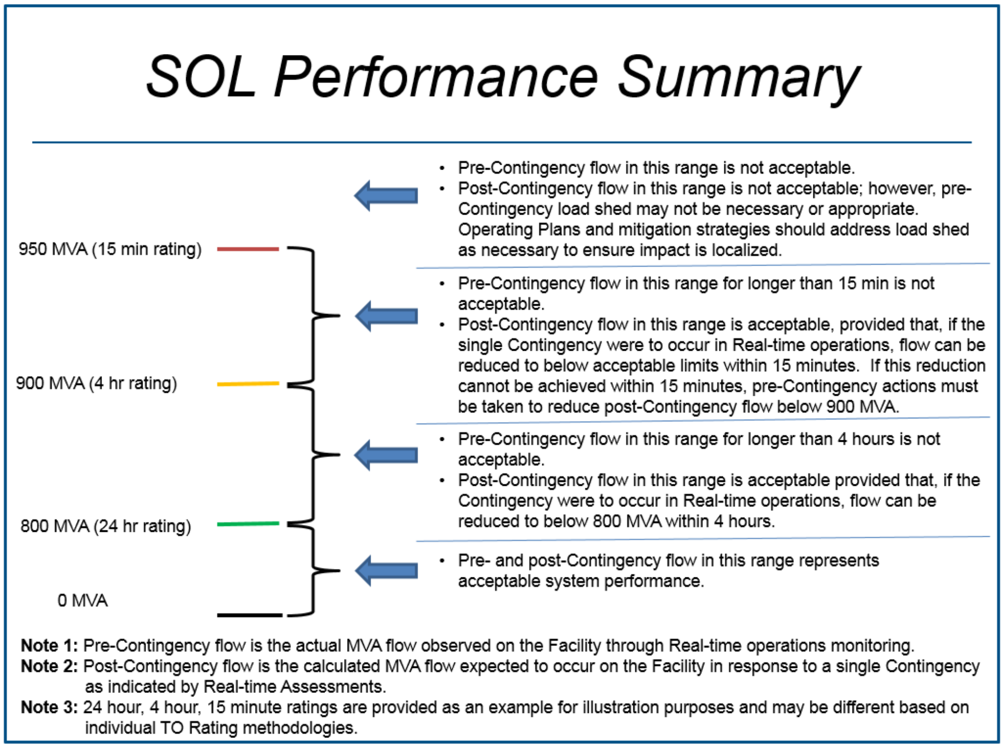
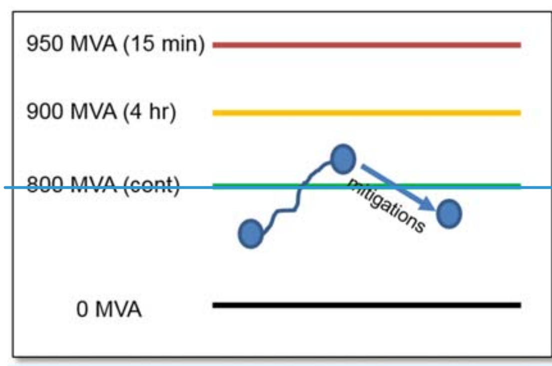


Figure 1. Facility Rating System Operating Limit Performance Summary



~~2In~~The following example scenarios describe appropriate operator action with respect to Figure 1:

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1. **Example 1 Scenario** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) Is it important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating.

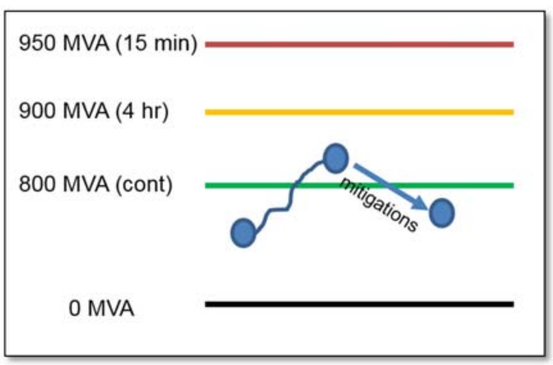

Figure 2. Example 1 Scenario – Pre-Contingency State

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2. **Example 2 Scenario** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, ~~Transmission Operators~~post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 ~~secure~~stable.

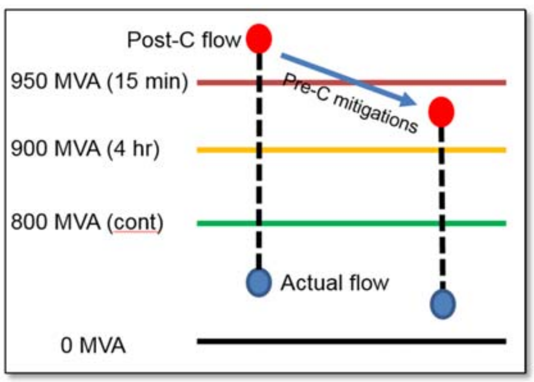

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **Example 3 Scenario** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending

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on how the line is rated based on the Transmission Owner's Facility Ratings Methodology. If this information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

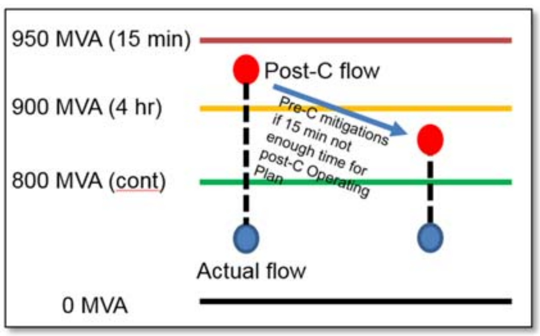

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **Example 4 Scenario** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would

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immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

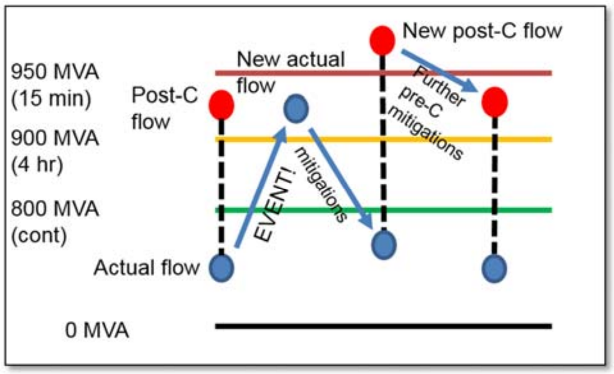

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

Steady State Voltage Limit Exceedance

SOL performance for ~~steady state voltage limits~~System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency ~~voltage limits~~System Voltage Limits are ~~expected~~required to be established by the TOP in accordance with the RC's SOL Methodology. FAC-011-4 Requirement R3 requires that the RC's SOL Methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3.

Normal ~~voltage limits~~ System Voltage Limits are typically applicable for the pre-Contingency state while emergency ~~voltage limits~~System Voltage Limits are applicable for the post-Contingency state. SOL exceedance with respect to these ~~voltage limits~~System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) ~~bus voltage limits~~System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside ~~acceptable~~ emergency ~~limits~~System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL Methodology. Real-time

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Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within ~~acceptable limits~~System Voltage Limits pre- or post-Contingency.

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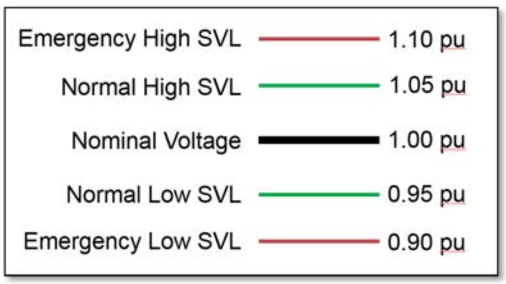

Figure 6. Example of a System Voltage Limit Set

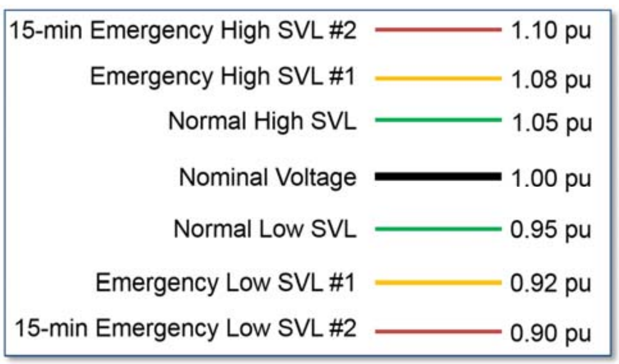

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

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Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. ~~ ~~Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

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Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. ~~Figure 2~~Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

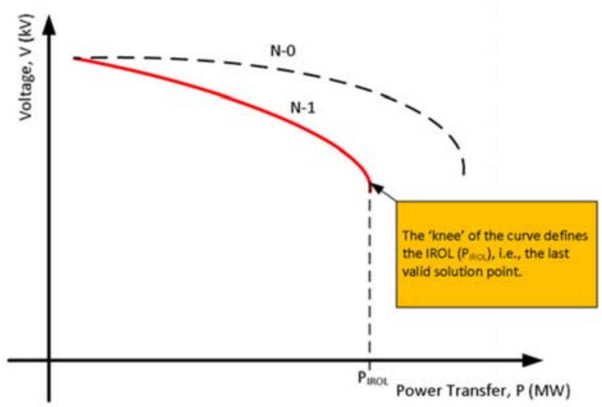

Figure ~~2~~8. Voltage Stability System Operating Limit Performance Summary

~~SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:~~

~~Actual flow on a Facility is above the Facility Rating for an unacceptable time duration~~
~~Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating~~
~~Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits~~
~~Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits~~
~~Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)~~

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SOL Exceedance and Operating Plans:

SOL exceedance occurs when the performance criteria as described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedance is determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedance is determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedance is identified through the evaluation of the actual state (or pre-Contingency state) and through an evaluation of Contingencies against that state. For stability limits, SOL exceedance is identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per ~~approved~~proposed FAC-011-~~2~~4, Requirement ~~R2~~R6, preventing SOL exceedances from ~~becoming an IROL.~~ escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or ~~operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15-minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1~~SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control**	**Use available effective actions and emergency procedures except Load shed consistent with**

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	loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.	timelines identified in the specific Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.	~~All of the above however,~~Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.

Table 1. Operating Plan Example

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APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to~~;~~: load forecasts~~;~~, generation output levels~~;~~, Interchange~~;~~, known Protection System and Special Protection System status or degradation~~;~~, Transmission outages~~;~~, generator outages~~;~~, Facility Ratings~~;~~, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

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Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

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Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

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Updated

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through October 17, 2018

Now Available

A 45-day formal comment period has been extended through **8 p.m. Eastern, Wednesday, October 17, 2018** for the following standards, implementation plan and proposed definition:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon (retirement)
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology (Updated)
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- Implementation Plan
- Proposed Definition - System Operating Limit

The following have been reposted due to identified typographical errors. The comment period has been extended to provide stakeholders adequate time to review the updated documents:

- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- FAC-015-1 - Requirement Rationale

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the proposed revisions to the FM and FMTD. If you experience any difficulties in using the electronic form, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, September 24, 2018.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial and additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 24 – October 17, 2018.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Updated
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- Proposed Definition - System Operating Limit

The following have been reposted due to identified typographical errors. The comment period has been extended to provide stakeholders adequate time to review the updated documents:

- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- FAC-015-1 - Requirement Rationale

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the proposed revisions to the FM and FMTD. If you experience any difficulties in using the electronic form, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, September 24, 2018.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial and additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 24 – October 17, 2018.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	8/24/2018
Comment Period End Date:	10/17/2018
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-015-1 AB 2 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 2 OT 2015-09 Establish and Communicate System Operating Limits PRC-002-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 Non-binding Poll IN 1 NB 2015-09 Establish and Communicate System Operating Limits Proposed Definition - System Operating Limit IN 1 DEF

There were 68 sets of responses, including comments from approximately 183 different people from approximately 117 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through FAC-011-4 Requirement R6, similar to the approach within the currently effective FAC standards, rather than through an SOL Exceedance definition. Do you agree with the performance criteria in Requirement R6?

2. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

3. The SDT acknowledges that requirement R6 could alternatively be located within a TOP or IRO standard; however, the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Proposed Requirement R6 was created to correspond with FAC-011-4 Requirement R6 in lieu of creating a definition for SOL Exceedance. Do you agree with Requirement R6?

4. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

5. The original posting of FAC-015-1 included six requirements. Industry comments to this original version indicated significant concerns. In response to these concerns, the SDT attempted to streamline and clarify the intended interactions between relevant functional entities and to consolidate the standard into fewer requirements. To achieve this the SDT:

- **Consolidated Requirements R1 – R5 in the original posting into three (R1 – R3) requirements,**
- **Clarified the roles of the Planning Coordinator and Transmission Planner in Requirements R1 – R3, and**
- **Clarified that Facility Ratings are "owner-provided" in Requirement R1.**

The SDT acknowledges that some of the requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc.; however, the Project 2015-09 SAR does not currently authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Do you support the revised FAC-015-1? Please provide any other comments regarding FAC-015-1.

6. Discussions within the SDT indicated concerns with eliminating some of the components of the approved SOL definition. While the industry feedback was largely supportive of the draft SOL definition provided in the informal posting, the SDT modified the proposed definition to incorporate some of the concepts in the approved version. The SDT believes that the revised definition posted for ballot represents an improvement over the definition provided in the informal posting. Reference the SOL rationale document for more information. Do you agree with the proposed SOL definition?

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Chris Wagner	Santee Cooper	1,3,5,6	SERC
					Anthony Noisette	Santee Cooper	1,3,5,6	SERC
					Weijian Cong	Santee Cooper	1,3,5,6	SERC
					Debbie Schneider	Santee Cooper	1,3,5,6	SERC

					Bridget Coffman	Santee Cooper	1,3,5,6	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC

					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Joseph Smith	Prairie Power	3	SERC
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Tara Lightner	Sunflower Electric Power	1	MRO

						Corporation		
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion, Con Ed and NBPower	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power	4	NPCC

	Authority		
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
David Kiguel	Independent	NA - Not Applicable	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Gregory Campoli	New York Independent	2	NPCC

						System Operator		
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
					Allan George	Sunflower Elect	1	MRO
					Jim Nail	City of Independence, Power and Light Department	5	MRO
					Robert Gray	Board of Public Utilities (BPU)	3	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					John Rhea	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
Associated Electric	Todd Bennett	3		AECI	Michael Bax	Central Electric Power	1	SERC

Cooperative, Inc.						Cooperative (Missouri)		
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC

					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through FAC-011-4 Requirement R6, similar to the approach within the currently effective FAC standards, rather than through an SOL Exceedance definition. Do you agree with the performance criteria in Requirement R6?

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Requirement R6.3 does not address SOL violations, but only checks against instability, cascading, or uncontrolled separation, even though this criteria is being used to evaluate performance on additional single or multiple contingency events (R5.2) for use in OPA and Real-time assessments. This suggests that SOL violations would be allowed for these contingencies.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

The language presented in the R6 is unclear and can lead to different interpretations. The language in R6 needs further clarification.

The drafting team needs to clarify that both actual pre-Contingency state and anticipated pre-Contingency state referred in R6.1 are referring to a TPL equivalent of P0 (system normal) state of the transmission system.

The drafting team should consider rephrasing the language in R6.2.1. Drafting team proposing not to allow usage of Emergency Ratings for contingency events irrespective of presence of operating plan is in complete variation of the planning standard requirements that allows usage of emergency ratings for contingencies described in R5.1.1.

The real time pre-Contingency state could be much different than the anticipated pre-Contingency state and the operating plan proposed for the anticipated pre-Contingency state may not be adequate during the real time pre-Contingency state. Under these conditions, not allowing the operators to use the Emergency ratings is very much disadvantageous and opposite to the intent of PRC-023 where the operator should be allowed to have flexibility to operate the system under Contingency conditions.

PacifiCorp recommends rephrasing 6.2.1 requirement as below

“Flow through Facilities are within applicable Emergency Ratings. Flow through a Facility must not be above the Facility’s highest available Rating, following an N-1 contingency.”

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF supports the efforts of the SDT to clarify for the industry what is considered SOL exceedance in the context of the IRO and TOP Standards. We appreciate the SDT listening to the concerns raised by industry regarding the previously proposed SOL Exceedance definition and we agree with the SDT's approach to abandon that potential change. We also agree with the SDT's concept that the Reliability Coordinator's SOL Methodology must address the system performance criteria to ensure consistent identification of SOLs. However, what is still not broadly understood is if each Facility must have an associated thermal-based SOL dependent on current system topology. In Requirement R3 it addresses establishment of a voltage-based SOL at each bus, but there isn’t a similar requirement for thermal ratings. Is it the expectation of the SDT that each Facility has a thermal-based SOL or can a subset (Flowgates?) be used to manage power flow on the system? This needs to be clearly stated in a requirement so that everyone is planning and operating the BES from the same understanding. Additionally, it’s not clear if exceeding the Normal Rating or normal System Voltage Limit is considered a SOL exceedance if you have a higher Emergency Rating or emergency System Voltage Limit for a specified time duration. It could be interpreted to say there isn’t SOL exceedance until you’re over the highest value of the Emergency Rating. This understanding translates to compliance expectations in the IRO and TOP Standards for when you must implement your Operating Plan. If we’re relying on the SOL whitepaper to clarify, then some entities may choose not to follow it saying it’s not mandatory and we’ll continue to have disagreement and confusion in the industry.

In order to support this project, the MRO NSRF needs to understand all the compliance expectations for SOL exceedances, including those associated with the IRO/TOP standards. Is every indication where the FAC-011 R6 performance criteria is exceeded considered a violation of FAC-014 R6 and/or an inadequate real time Operating Plan? Are current operating protocols, which are agreed upon by the Transmission Operator and Reliability Coordinator and allow for temporary exceedances while control actions (such as LMP binding) are being implemented, now going to be prohibited and considered violations? As the proposed performance criteria (for post-contingent thermal and voltage exceedances) does not include any time threshold (in analogy with Tv for IROLs) does that imply the Transmission Operator and Reliability Coordinator would NOT be given any timeframe (such as 30 minutes) to correct an exceedance (particularly post-contingent thermal or voltage exceedances), before it becomes a reportable event and a potential compliance issue? Will the performance criteria be identical independently of the system state (i.e. if the system is in N-1 as opposed to N-4, or even more severe, topology conditions)? Is the Transmission Operator expected to perform a timing analysis to determine if ramp rates, start-up times and location and amount of load shedding are adequate every time it operates above the Normal Rating but below Emergency Rating to verify its Operating Plan will eliminate exceedance within the timeframe of the Emergency Rating? Would the proposed performance criteria not allow for any regional differences even in cases where a Reliability Coordinator is not registered as a Transmission Operator, but has critically important mitigating control actions under its responsibilities? We do not want to unintentionally approve a standard that creates overly burdensome compliance demonstration expectations for the industry, while the SER project is actively seeking ways to streamline and reduce these burdens. Since the SDT cannot answer all these questions, then we request NERC staff to draft a CMEP Practice Guide to inform the industry of the compliance expectations for SOLs as applied in the FAC, IRO and TOP standards.

Will entities be forced to create separation between the highest Emergency, Emergency, and Normal ratings if they are currently the same? An example is a conductor limited transmission line with a 10-minute time constant where all three ratings are identical. Does an entity have to de-rate the line by increments of sag temperature or percentage to create time between ratings or be in violation of the FAC-011-4 timing requirements. Short time frames of under 30 minutes could also lead to a violation of FAC-011-4 R6.5. Short time frames under 30 minutes aren't sufficient time for a system operator to consider "all" other available system adjustments before implementing load shedding.[A1]

To further explain, we believe the proposed performance criteria in FAC-011-4 Requirement R6 seems to capture the essence of SOL exceedance. However, we are concerned the proposed language creates a significant reliability/compliance burden for Transmission Operators and Reliability Coordinators as follows:

1. R6.2 - The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception. When coupled with R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA. This is an infeasible expectation for the Transmission Operator and Reliability Coordinator to include in their RTAs and OPAs, since R5.1.1 contains no caveats to limit the list of applicable single contingencies.
2. R6.2.1 - The flows on a transmission element may exceed the applied Emergency Rating during the dynamic time period, but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the *"applicable Emergency Rating"* for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis. It may be that the SDT does not intend to pull in dynamics in 6.2.2 but it is a logical reading of the standard.
3. R6.2.3 - As noted above, although this is the desired result, it is infeasible to perform dynamic analyses of all R5.1.1 contingencies as part of either an RTA or an OPA. In fact, it is an extremely expensive proposition to perform any real time dynamic simulations due to the complexities of maintaining an accurate dynamic model that incorporates traditional transmission equipment let alone the myriad of user written or proprietary dynamic models in use today for FACTs devices and variable generation.
4. R6.3 and R6.4 contain the same problems as noted above. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the Reliability Coordinator to provide a very limited list of contingencies. Still, even with a limited list, the language of R6 and its sub-parts does not limit the scope of what a Transmission Operator would be required to run under FAC-014-3 (see R2 of that standard). Rather, FAC-011-4 R6 language implies that a Transmission Operator would be required to evaluate all of the contingencies identified by a Reliability Coordinator, not just those that apply to the Transmission Operator's footprint. Note that FAC-014-3 R2 limits the Transmission Operator to identifying SOLs to its footprint, but it does not limit the contingencies a Transmission Operator would need to consider.
5. R6.5 - The standard incorrectly eliminates planned load shedding from consideration when a RAS or UVLS programs may have specifically established the need to take such action to maintain system stability for the particular contingencies under consideration.

We offer the following proposed improvements to address the comments above:

- R6.1.1, R6.1.2, R6.2.1 and R6.2.2 could be improved by clarifying that these sub-requirements are only describing steady-state conditions. Each requirement could have the following leading statement added: *"Under steady-state analysis:"*.

- In addition, R6.2.1 and R6.2.2 would also benefit from adding the word *"Anticipated"* ahead of the terms *"Flow"* and *"Voltages"* in these requirements, respectively, to make it clear that these are potential system flows and voltages, not real time flows and voltages, being evaluated.

Regarding the scope of dynamic simulations, the best location to make modifications is likely the R5 and R5.1 language, not R6. Proposed modifications are as follows:

- R5 - Strike *"and performing the Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study"* since this language is redundant to the R6 performance criteria language that will require these contingencies to be evaluated as part of the RTA and OPA. With this removed, R5 is tailored to only describe what contingency events need to be examined for the identification of SOLs.

R5.1 - Remove the language regarding *"determining stability limits and performing OPAs and RTAs"* and add *"for use in determining steady state SOLs",* since the SOL methodology should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to

R5.3.

- R5.2 - Remove *"for use in performing Operational Planning Analysis and Real-time Assessments"* since, again, this is adequately covered by R6, and add in language as follows *"for use in determining steady state SOLs"*.

R5.3 - Strike the word *"additional"* from the existing R5.3 language and add the following to the end of the requirement: *"where the identified single Contingency events involving the loss of a generator, transmission circuit, transformer, shunt device, or single pole block in a monopolar or bipolar high voltage direct current system must simulate either: (a) Normal Clearing of a single phase to ground or three phase Fault (whichever is more severe) or (b) tripping without a Fault condition"*.

- Regarding the Transmission Operator performing a certain set of contingencies, the R6.2, R6.3 and R6.4 language could all be modified to state: *"The evaluation of applicable potential single Contingencies …"* (for R6.2) and *"The evaluation of the applicable potential Contingencies …"* (for R6.3 and R6.4).

R6.5 could be improved by clarifying that RAS and UVLS actions should be implemented in the stability analysis, as applicable. The SDT should also recognize that underfrequency load shedding (UFLS) may be a necessary part of system stabilization once a RAS operates if that RAS is creating a planned islanded system. As such, UFLS may also be a warranted load shedding component when performing stability analysis. R6.5 language could be modified by adding *"planned load shedding, other than Remedial Action Scheme (RAS) or UVLS action, is acceptable …"* and then adding a new sentence that reads, *"The use of UFLS programs should only be simulated when incorporated as part of the system design to maintain stability (e.g., RAS)."*

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	

NPPD supports comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	No
Document Name	

Comment

NRECA agrees that it is not necessary to create a definition of SOL Exceedance, but still believes the new FAC-011-04 R6 requirement creates undue compliance burden by prescribing an excessive number of sub-requirements. The structure of R6 is confusing. Many of the sub- requirements that are not standalone with references to other requirements in the proposed standard.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comments provided by NRECA.

NRECA agrees that it is not necessary to create a definition of SOL Exceedance, but still believes the new FAC-011-04 R6 requirement creates undue compliance burden by prescribing an excessive number of sub-requirements. The structure of R6 is confusing. Many of the sub- requirements that are not standalone with references to other requirements in the proposed standard.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No

Document Name	

Comment
The use of the undefined term 'instability' could lead to inconsistent results and result in additional compliance burdens that add little to no reliability benefit. As used in FAC-011 R6, instability is not limited to the BES or wide area but instead, as currently worded, applies to ANY instability that has ANY impact to any element or facility. R6.1.3 and 6.2.3 should be limited to the interconnection or at the very least the wide-area to prevent misunderstanding.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

MidAmerican Energy Company (MEC) understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance.

MidAmerican supports the SDT's proposal to create a definition of SOL exceedance, **as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities**. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations

We certainly appreciate the SDT's rational approach of not proceeding with the proposed definition of SOL exceedance having in mind significant number of negative comments which were received in October, 2017, primarily from MISO and SPP Regions.

Unfortunately, instead of patient continuation of efforts to adjust and improve proposed definition of SOL exceedance, the NERC Standard Drafting Team decided to take, in our view, **inappropriate approach of incorporating that controversial and arguable (although somewhat modified) definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard. We consider this pathway as potentially worse and more risky in comparison with coming up with definition of SOL Exceedance. The reason for such a characterization is that by substituting definition of SOL Exceedance via embedding it as a performance criteria into FAC-011-4, the SDT would expose a number of TOPs and RCs to risk of directly violating FAC-011-4 (Requirement 6) and associated penalties, if (non-agreed upon in terms of definition) exceedances of system operating limits occur either in RTA or OPA**.

Furthermore, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with an approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance **and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better** than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating

Plans, in a timely manner.

Fundamental principles and complexities of real power systems do not allow for ignoring the time dimension that always exist when implementing corrective control actions when temporary exceedances of SOL occur, especially in RTA. That was, unfortunately, overlooked in proposed versions of FAC-011-4 and FAC-014-3.

The role of SOL exceedance definition (or performance criteria within FAC-0114-R6), in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate that infrastructure**.

Our quite specific reasons for NOT agreeing with the proposed Requirement 6 of FAC-011-4 are:

1. **Requirements 6.1.1; 6.1.2 and 6.2.1** use the phrase "*when System adjustments to return the flow/voltage within its Normal Rating/Voltage Limits could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits".*

We would like to show our appreciation to the SDT for their reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance. In this particular case we are pleased that the SDT now considers exceedance of Emergency (rather than Normal) limits as a reportable event.

However, there is a problem with using the phrase "*could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits" as* clearly pointed out by Mr. Terry Volkmann. We completely agree with his comment: "*This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate…. TOP (in MISO and SPP reliability footprints) cannot perform such analyses, because the RC/market operator has all the data and tools to do the analysis….* ***This analysis is best served as an internal control not a compliance obligation*****.** " MEC agrees with Mr. Volkmann that above mentioned quoted phrase shall be eliminated from the draft of the standard.

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6

The second problem is that it is necessary to differentiate between flow exceedances and voltage exceedances in terms of risk to the equipment and the time tolerance.

We recommend the following definition:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***

- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***

- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1\.

   i.

      a. *Steady state Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings*.

      b. *Steady state Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits*.

1. **Requirements 6.1.3 and 6.2.3** refer to preventing instability, cascading or uncontrolled separation.

- We find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.1.3 and 6.2.3 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

We recommend the following definition:

- ***Any established stability limit (non-IROL) or limit that may cause cascading outages or uncontrolled separation shall not be exceeded***

for longer than the 30 minutes, or defined by Operating Plan.

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1.
    i.
        a. *Any established stability limit (non-IROL) is mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology and Operating Plan, or with RC's approved post-contingency action plan.*
        b. *System-wide Instability, Cascading or uncontrolled separation do not occur.*

2.
    i.
        a. *Any established stability limit (non-IROL) is mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology and Operating Plan, or with RC's approved post-contingency action plan.*
        b. *System-wide Instability, Cascading or uncontrolled separation do not occur*.

1. **Requirement 6.2.1** is of particular importance and probably the single, most frequent concern in present industry's practice. MidAmerican Energy Company appreciates SDT's reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance/performance criteria. However, we would like to draw the SDT's attention to the following issues with their present formulation of the Requirement 6.2.1, which states that:

"*provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings*. ***Flow through a Facility must not be above the Facility's highest Emergency Rating*.**"

We would like to point out several issues with regard to this formulation:

- First, **the proposed definition does not recognize time-frame associated with exceedances of the Facility's highest Emergency Rating**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). Others exceedances may last several minutes(5-30 minutes, just for sake of example) due to time constraints associated with operators' response to these exceedances and physical reality/timing of corrective control actions that need to be implemented. More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.2.1 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

- Second, regarding the phrase "*Flow through a Facility must not be above the Facility's highest Emergency Rating*", the SDT's formulation appears to be based on the Project 2014 NERC White paper.
Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability**

impact so that it has localized impact". Subsequent version of the NERC White Paper (revision of January 2015) introduced statement that "Post-contingency flow in this range is not acceptable" . **This revision, with a major impact, was never presented to the industry, never approved by the Industry and, in our opinion, was step in the wrong direction. The most recently published revision adds clarity and improved formulations, but still departs from the original concept and ignores time dimension that is necessary to implement corrective control actions, especially for inevitable short term exceedances in RTA, on a contingency basis.**

- Third, the SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "performance criteria/SOL exceedance" may easily cause an incorrect expectation that TOP/RC's control actions response to these two types of exceedances should be similar, in terms of timing, logging and recording.

- Fourth, **it is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability**.

- Fifth, there is a problem with using the phrase "*could be executed and completed within the specified time duration of those Emergency Ratings" as* clearly pointed out by Mr. Terry Volkmann. We completely agree with his comment: "*This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate…. TOP (in MISO and SPP reliability footprints) cannot perform such analyses, because the RC/market operator has all the data and tools to do the analysis….* ***This analysis is best served as an internal control not a compliance obligation***. " MEC agrees with Mr. Volkmann that this phrase shall be eliminated from the draft of the standard.

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis)? It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6.

• Sixth, regarding the **language in FAC-011-4 (R6.2.1)** "*Flow through a Facility must not be above the Facility's highest Emergency Rating"*, let's consider the following scenario. TOP operates in REAL-TIME with one scheduled outage (N-1 topology). Then a fault occurs (single event such as bus fault or similar) and takes out of service two (or more) facilities, thus bringing the system in real-time into N-3 topology condition. Now, RTCA starts showing overloading for next single contingency (N-4).

The concern is if the language in the draft of the standard assumes that **the performance criteria are identical, independently of the system state** (i.e. if the system is in N-1 as opposed to N-3, or even more severe, topology conditions). We certainly understand that in OPA such a scheduled outage would not be approved if it causes SOL exceedances. However, what will be applicable performance criteria if that event happens in real-time due to single event? Of course TOP will implement its Operating Plan to correct the exceedance, but due to significantly deteriorated topology (for which the system was never designed) it may take longer time period to eliminate exceedance on a contingency basis. Or, analysis may show that only firm load shedding may eliminate the exceedance.

The issue is that if the same performance criteria are applicable independently of topology conditions, in order to avoid performance criteria violation (on a contingency basis) the only viable option might be pre-contingent firm load shedding to correct contingency based (not real-time) exceedance.

We recommend the following definition for 6.2.1:

- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1.

   i. *The evaluation of potential single Contingencies listed in Part 5.1.1 for system intact and N-1 operating conditions, against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:*

      a. *Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings. Post-Contingency flow in this range that is not mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology, or without RC's approved post-contingency action plan, constitutes reportable exceedance to RC. The Operating Plan developed and mutually agreed to by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding, while normal congestion relief control actions are being implemented, to ensure potential impact is localized. Flow through a Facility must not be above the Facility's highest Emergency Rating.*

      b. *Voltages are within emergency System Voltage Limits. Post-Contingency voltage outside of the emergency System Voltage Limits that is not mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology, or without RC's approved post-contingency action plan, constitutes reportable exceedance to RC. The Operating Plan developed and mutually agreed to by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding, while normal control actions for eliminating System voltage exceedance are being implemented, to ensure potential impact is localized.*.

Rationale for using Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating.*** It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

- **In contrast to this, we believe that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage**.

- Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

- We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this manner and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

- The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that issuing a new Short Term Emergency rating would be an alternative for the TOP to pursue rather than agreeing with its RC on a post-contingency action plan. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment** (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data and technical facilities justifications**. Consequently, as opposed to being "pushed/forced" to using technically unjustified short-term emergency/load shedding ratings, each TOP and RC might need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

1. **Requirements 6.3 and 6.4**:

Our comments can be formulated in the following red-line (highlighted in yellow changes):

1.

   i. *The evaluation of the potential Contingencies identified in Part 5.2 (which are not mitigated within the time-frame specified in, and in accordance with, the RC's SOL methodology) against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.*

The evaluation of the potential Contingencies identified in Part 5.3, (which are not mitigated within the time-frame specified in, and in accordance with, the RC's SOL methodology) demonstrates that instability does not occur.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Requirement 6.2.2 should be modified to mirror 6.2.1: **6.2.2.** Voltages are within applicable emergency System Voltage Limits, provided that System adjustments could be executed and completed within the specified time duration of those emergency System Voltage Limits.	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
ReliabilityFirst votes in the negative for the following two reasons. 1. For requirement R6 part 6.5, ReliabilityFirst believes not being permitted to plan to drop load prior to taking all other actions seems is not technically correct. Here are a few real life scenarios that ReliabilityFirst is aware of: there are Remedial Action Schemes that drop non-firm load for first contingency events. There is another Remedial Action Scheme that drops 1/3 of the total station load for a breaker failure event.	

RF recommends the following changes to Part 6.5 for consideration: "In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding [non-firm load] is acceptable [and planned shedding of firm load is acceptable] only after all other available System adjustments have been made [or where pre-approved by state regulators, and the shedding of load with Remedial Action Schemes.]

2. For Requirement R6 parts 6.1.1, 6.1.2, and 6.2.1, these three statement assume that the ONLY way that flows, voltages can be controlled within a specified time duration is with system adjustments. There are times when it is known that voltages or flows will change without the operator making any system adjustments. The operator could know that the 2nd shift at a factory ends in 5 minutes, and that there is no 3rd shift.

RF recommends the following changes to Part 6.1.1, 6.1.2 and 6.2.1 for consideration:
6.1.1 - Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used [when flows can be returned to within Normal Ratings within the specified time duration of those Emergency Ratings.]
6.1.2 - Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used [when voltage can be returned to within its normal System Voltage Limits within the specified time duration of those emergency System Voltage Limits.]
6.2.1 - Flow through Facilities are within applicable Emergency Ratings, [provided that flows can be returned to within Normal Ratings System within the specified time duration of those Emergency Ratings]. Flow through a Facility must not be above the Facility's highest Emergency Rating.

Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

R6 uses the term "performance criteria". This is the same term used in R6 in FAC-014-3 (see NIPSCO comments for question 4). Using the same term in two different standards with different context is confusing. For FAC-011-4 R6 NIPSCO suggests eliminating the phrase "Bulk Electric System performance criteria" and just placing a ":" after the word "following".

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

See MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy)" does not agree with the performance criteria in FAC-011-4 Requirement R6 and believes that the language is ambiguous and unnecessary. In particular, the use of the term "instability" in Requirements R6.1.3 and R6.2.3 without any qualifiers may broaden the scope of the language, which could lead to inconsistent results. CenterPoint Energy recommends that the SDT revise the language in Requirements R6.1.3 and R6.2.3 to clarify that instability that adversely impacts the reliability of the BES is what is intended.

Likes 0	
Dislikes 0	

Response

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	No
Document Name	

Comment

Entergy supports comments submitted by MidAmerican Energy Company.

Likes 0	
Dislikes 0	

Response

Kelsi Rigby - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS does not have an issue with the performance criteria set forth in FAC-011-4 R6. However, the use of performance criteria could still result in ambiguity regarding what qualifies as a "SOL Exceedance." For this reason, AZPS recommends that the SDT reconsider use of a defined term for "SOL Exceedance." Additionally, if there is intent to continue to use the term "SOL exceedance" within the body of reliability standards, then both

industry and the ERO Enterprise would benefit from the clarity that would result from a definition of the term.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports the SDT's proposal to create a definition of SOL exceedance, **as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities**. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations

NV Energy believe the SDT took an **inappropriate approach of incorporating that controversial and arguable (although somewhat modified) definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard. We consider this pathway as potentially worse and more risky in comparison with coming up with definition of SOL Exceedance. The reason for such a characterization is that by substituting definition of SOL Exceedance via embedding it as a performance criteria into FAC-011-4, the SDT would expose a number of TOPs and RCs to risk of directly violating FAC-011-4 (Requirement 6) and associated penalties, if (non-agreed upon in terms of definition) exceedances of system operating limits occur either in RTA or OPA**.

Furthermore, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with an approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance **and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better** than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

Fundamental principles and complexities of real power systems do not allow for ignoring the time dimension that always exist when implementing corrective control actions when temporary exceedances of SOL occur, especially in RTA. That was, unfortunately, overlooked in proposed versions of FAC-011-4 and FAC-014-3.

The role of SOL exceedance definition (or performance criteria within FAC-0114-R6), in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate that infrastructure**.

We appreciate that the SDT listened to the industry's comments and gradually improved the definition of SOL exceedance. In particular, we are pleased that the SDT now considers exceedance of Emergency (rather than Normal) limits as a reportable event.

However, there is a problem with using the phrase "*could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits*". We agree with previous commenting of: "*This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate….* ***This analysis seems to be better served as an internal control not a compliance obligation.***'

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration

of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6

The second problem is that it is necessary to differentiate between flow exceedances and voltage exceedances in terms of risk to the equipment and the time tolerance.

We share the industry recommendation of the following definition:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***
- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***
- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

1. **Requirements 6.1.3 and 6.2.3** refer to preventing instability, cascading or uncontrolled separation.

- We find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.1.3 and 6.2.3 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

We recommend the industry discussed following definition:

- ***Any established stability limit (non-IROL) or limit that may cause cascading outages or uncontrolled separation shall not be exceeded for longer than the 30 minutes, or defined by Operating Plan.***
-

1. **Requirement 6.2.1** is of particular importance and probably the single, most frequent concern in present industry's practice. MidAmerican Energy Company appreciates SDT's reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance/performance criteria. However, we would like to draw the SDT's attention to the following issues with their present formulation of the Requirement 6.2.1, which states that:

"*provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings*. ***Flow through a Facility must not be above the Facility's highest Emergency Rating*.**"

We would like to point out several issues with regard to this formulation:

- First, **the proposed definition does not recognize time-frame associated with exceedances of the Facility's highest Emergency Rating**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). Others exceedances may last several minutes(5-30 minutes, just for sake of example) due to time constraints associated with operators' response to these exceedances and physical reality/timing of corrective control actions that need to be implemented. More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.2.1 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

- Second, regarding the phrase "*Flow through a Facility must not be above the Facility's highest Emergency Rating*", the SDT's formulation appears to be based on the Project 2014 NERC White Paper. Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability impact so that it has localized impact**". Subsequent version of the NERC White Paper (revision of January 2015) introduced statement that "Post-contingency flow in this range is not acceptable" . **This revision, with a major impact, was never presented to the industry, never approved by the Industry and, in our opinion, was step in the wrong direction. The most recently published revision adds clarity and improved formulations, but still departs from the original concept and ignores time dimension that is necessary to implement corrective control actions, especially for inevitable short term exceedances in RTA, on a contingency basis.**

- Third, the SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "performance criteria/SOL exceedance" may easily cause an incorrect expectation that TOP/RC's control actions response to these two types of exceedances should be similar, in terms of timing, logging and recording.

Fourth, **it is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability**.

- **The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis)**? It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6.

• Fifth, regarding the **language in FAC-011-4 (R6.2.1)** "*Flow through a Facility must not be above the Facility's highest Emergency Rating"*, let's consider the following scenario. TOP operates in REAL-TIME with one scheduled outage (N-1 topology). Then a fault occurs (single event such as bus fault or similar) and takes out of service two (or more) facilities, thus bringing the system in real-time into N-3 topology condition. Now, RTCA starts showing overloading for next single contingency (N-4).

The concern is if the language in the draft of the standard assumes that **the performance criteria are identical, independently of the system state** (i.e. if the system is in N-1 as opposed to N-3, or even more severe, topology conditions). We certainly understand that in OPA such a scheduled outage would not be approved if it causes SOL exceedances. However, what will be applicable performance criteria if that event happens in real-time due to single event? Of course TOP will implement its Operating Plan to correct the exceedance, but due to significantly deteriorated topology (for which the system was never designed) it may take longer time period to eliminate exceedance on a contingency basis. Or, analysis may show that only firm load shedding may eliminate the exceedance.

The issue is that if the same performance criteria are applicable independently of topology conditions, in order to avoid performance criteria violation (on a contingency basis) the only viable option might be pre-contingent firm load shedding to correct contingency based (not real-time) exceedance

We recommend the following industry discussed definition for 6.2.1:

- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

We believe there is need for using a Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating****.* It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

In contrast to this, we believe that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

- Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

- We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this manner and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

- The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that issuing a new Short Term Emergency rating would be an alternative for the TOP to pursue rather than agreeing with its RC on a post-contingency action plan. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment** (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data and technical facilities justifications**. Consequently, as opposed to being "pushed/forced" to using technically unjustified short-term emergency/load shedding ratings, each TOP and RC might need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

We believe the SOL exceedance definition did create an unnecessary compliance burden. However, the approach the SDT took does not reduce the compliance burden by moving the SOL Exceedance definition to a requirement. Requirement R6 is overly complicated and confusing. It has 11 sub-parts and references other requirements four separate times. Compliance standards should be clear and should be able to stand alone without the need to cross reference other requirements.

Likes 0	
Dislikes 0	

Response

Tommy Drea - Dairyland Power Cooperative - 5

Answer	No
Document Name	

Comment

DPC supports the comments of MRO NSRF.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group (SSRG) believes that the performance criteria as described in R6 should be simplified and imbedded where appropriate in the other requirements of FAC-011-4. For example, performance criteria pertaining to steady state voltage should be included in R3.

Likes 0	
Dislikes 0	

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer	No
Document Name	

Comment

For Pre-Contingency conditions, emergency limits should not be allowed to be used.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy requests further clarification on the use of “pre-Contingency state” in R6.2. Was it the drafting team’s intent that an RC should anticipate a “pre-Contingency state”? Was this a typographical error? Should “post-Contingency state” be used instead?

Duke Energy is unclear on the expectations for R6.4. Is it the drafting team intent that with the use of the term “demonstrates” in R6.4, that entities are required to do stability studies in Real-time? The drafted language appears to be more suitable for Planning Coordinators and Transmission Planners, not for Operators of the BES in Real-time. We suggest the drafting team consider the following language for R6.4:

“The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that the system will be operated within stability limits.”

Should other Time Horizons be considered for R6 as well, (Same Day)?

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

General Observation

The companies believe reliability and establishing compliance thresholds are better served by keeping performance criteria within the performance Standards, e.g. TOP and IRO Standards, and keeping Standards that establish a methodology free from such performance criteria.

Like the SDT’s statement in Question 3, the companies agree that to address the issue, revisions would likely need to be made within a TOP or IRO standard and the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards.

Suggestion: Add Flexibility

The companies recognize each Registered Entities' system is unique in design, complexity, footprint, and Facilities. To address the differences between systems across the BES, the companies suggest FAC-011-4 R6 language provide flexibility to accomplish the reliability outcomes offered in the proposed revisions by leveraging entities' FAC-008 Facility Rating Methodology and applicable internal documents to guide:

- When Normal and Emergency Ratings/Voltage limits are used under pre or post-contingent conditions, and
- The allowable time duration for the applicable condition.

Suggestion: Remove Prescriptive Language

Also, the companies suggest removing prescriptive language to provide entities more flexibility executing Requirement 6. Replacing the NERC Glossary Terms, "Normal Ratings" and "Emergency Ratings" with the words "applicable ratings" or "applicable voltage limits" will provide the suggested flexibility without compromising BES reliability.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

Although the current FAC standards include performance criteria, MISO believes that they should reside in IRO and TOP standards. The FAC standard should focus on defining acceptable Operating Limit methodologies. With respect to the proposed performance criteria, MISO has the following concerns:

- Revised standard and SOL exceedance definition appears to imply that exceeding the System Operating Limit (SOL) is not allowed. This makes SOLs more restrictive in management than IROLs, for which there is an allowance to exceed the rating as long as the load is reduced to below the rating prior to exceeding the Tv of the facility. There is no Tv allowance for SOLs, as the definition is currently written.

In particular, the performance criteria as written fail to allow time for the RC or TOP to respond to an event, and readjust the system without immediately putting them in violation of the performance criteria. For example, RTA will show all elements within their emergency ratings per the criteria, but then a contingency occurs and the next RTA shows one or more elements above the highest emergency rating.

- Transmission system could be underutilized, if the SOL Exceedance definition is implemented as currently written.
- Planning standards recognize exceedances of operating limits will occur, and require a plan to mitigate those exceedances. This definition does not allow for the same to occur in Operations

- R6.5 appears to disallow load shedding that may have been specifically designed as part of a RAS or UFLS scheme.

Finally, any change to SOL exceedance in the IRO and TOP standards need to be clear that exceeding a non-IROL SOL, particularly post contingency, is not a violation of any operating standard or criteria.	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Do not agree with 6.5, too restrictive. Should be allowed to apply non-consequential load loss.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	

The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception.

R6.2.1 - The flows on transmission element may exceed the applied Emergency Rating during the dynamic time period but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the "applicable Emergency Rating" for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis

R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre -Contingency state (Real-ti monitoring and Real Assessments) and anticipated pre -Contingency state (Ope or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

R6.3 and R6.4 contain the same problems. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the RC to provide a very limited list of contingencies.

6.5. In determining the System’s response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

R6.5 - The standard incorrectly eliminates planned load shedding from consideration when RAS or UVLS programs may have specifically established to take such action to maintain system stability for the particular contingencies under consideration.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA supports the comments submitted by MRO.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

American Transmission Company LLC (ATC) supports the efforts of the SDT to clarify for the industry what is considered SOL exceedance in the context of the IRO and TOP Standards. We appreciate the SDT listening to the concerns raised by industry regarding the previously proposed SOL Exceedance definition and we agree with the SDT's approach to abandon that potential change. We believe the proposed performance criteria in FAC-011-4 Requirement R6 seems to capture the essence of SOL exceedance. We do agree with the SDT's concept that the Reliability Coordinator's (RC) SOL Methodology must address the system performance criteria to ensure consistent identification of SOLs.

However, ATC is concerned the proposed language creates a significant reliability/compliance burden for RCs and Transmission Operators (TOP) as follows:

- R6.2 - The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception. When coupled with R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA. This is an infeasible expectation for the RC and TOP to include in their RTAs and OPAs, since R5.1.1 contains no caveats to limit the list of applicable single contingencies.

- R6.2.1 - The flows on a transmission element may exceed the applied Emergency Rating during the dynamic time period, but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the *"applicable Emergency Rating"* for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis. It may be that the SDT does not intend to pull in dynamics in 6.2.2 but it is a logical reading of the standard.
- R6.2.3 - As noted above, although this is the desired result, it is infeasible to perform dynamic analyses of all R5.1.1 contingencies as part of either an RTA or an OPA. In fact, it is an extremely expensive proposition to perform any real time dynamic simulations due to the complexities of maintaining an accurate dynamic model that incorporates traditional transmission equipment let alone the myriad of user written or proprietary dynamic models in use today for FACTs devices and variable generation.
- R6.3 and R6.4 contain the same problems as noted above. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the RC to provide a very limited list of contingencies. Still, even with a limited list, the language of R6 and its sub-parts does not limit the scope of what a TOP would be required to run under FAC-014-3 (see R2 of that standard). Rather, FAC-011-4 R6 language implies that a TOP would be required to evaluate all of the contingencies identified by an RC, not just those that apply to the TOP's footprint. Note that FAC-014-3 R2 limits the TOP to identifying SOLs to its footprint, but it does not limit the contingencies a TOP would need to consider.
- R6.5 - The standard incorrectly eliminates planned load shedding from consideration when a RAS or UVLS programs may have specifically established the need to take such action to maintain system stability for the particular contingencies under consideration.

ATC offers the following proposed improvements to address the comments above:

- R6.1.1, R6.1.2, R6.2.1 and R6.2.2 could be improved by clarifying that these sub-requirements are only describing steady-state conditions. Each requirement could have the following leading statement added: *"Under steady-state analysis:"*.

- In addition, R6.2.1 and R6.2.2 would also benefit from adding the word *"Anticipated"* ahead of the terms *"Flow"* and *"Voltages"* in these requirements, respectively, to make it clear that these are potential system flows and voltages, not real time flows and voltages, being evaluated.

Regarding the scope of dynamic simulations, the best location to make modifications is likely the R5 and R5.1 language, not R6. Proposed modifications are as follows:

- R5 - Strike *"and performing the Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study"* since this language is redundant to the R6 performance criteria language that will require these contingencies to be evaluated as part of the RTA and OPA. With this removed, R5 is tailored to only describe what contingency events need to be examined for the identification of SOLs.

- R5.1 - Remove the language regarding *"determining stability limits and performing OPAs and RTAs"* and add *"for use in determining steady state SOLs",* since the SOL methodology should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to R5.3.should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to R5.3.
- R5.2 - Remove *"for use in performing Operational Planning Analysis and Real-time Assessments"* since, again, this is adequately covered by R6, and add in language as follows *"for use in determining steady state SOLs"*.

- R5.3 - Strike the word *"additional"* from the existing R5.3 language and add the following to the end of the requirement: *"where the identified single Contingency events involving the loss of a generator, transmission circuit, transformer, shunt device, or single pole block in a monopolar or bipolar high voltage direct current system must simulate either: (a) Normal Clearing of a single phase to ground or three phase Fault (whichever is more severe) or (b) tripping without a Fault condition"*.

- Regarding the TOP performing a certain set of contingencies, the R6.2, R6.3 and R6.4 language could all be modified to state: *"The evaluation of applicable potential single Contingencies …"* (for R6.2) and *"The evaluation of the applicable potential Contingencies …"* (for R6.3 and R6.4).

- R6.5 could be improved by clarifying that RAS and UVLS actions should be implemented in the stability analysis, as applicable. The SDT should also recognize that underfrequency load shedding (UFLS) may be a necessary part of system stabilization once a RAS operates if that RAS is creating a planned islanded system. As such, UFLS may also be a warranted load shedding component when performing stability analysis. R6.5 language could be modified by adding *"planned load shedding, other than Remedial Action Scheme (RAS) or UVLS action, is acceptable …"* and then adding a new sentence that reads, *"The use of UFLS programs should only be simulated when incorporated as part of the system design to maintain stability (e.g., RAS)."*

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

The criteria given are not clear as written such that they appear to occur in the Real-time horizon and apply to real-time operations rather than in the Operations Horizon as stated. As a consequence, the criteria do not seem to meet a methodology requirement but an operating one. Specifically, the identification of real-time monitoring and assessment as a demonstration is inappropriate for a FAC methodology requirement and belongs in TOP and IRO standards relating to operations. We believe there should not be an operating requirement in FAC-011 and in our opinion this is a poor practice and should be shelved. The Standard "families" set certain expectations and should be respected because to do otherwise will create risks of inconsistency. If the TOP and IRO standards need amending, then amend them!

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SRP is concerned the language in 6.5 may be too limiting, specifically the phrase “only after **all** other available System adjustments”. SRP suggests either adjusting the language to state “after other reasonable System adjustments have been made”, or to state “while other system adjustments are being made”. It may be necessary to respond first with load shed while other system adjustments are being made, then returning the load. The language should allow entities to use all available tools and determine the best process for maintaining stability of the system.

Also, SRP recommends retaining some of the language in FAC-011-3 R2.3 and R2.4 explicitly identifying acceptable post-Contingency actions. Consideration of post-Contingency actions is appropriate in an SOL methodology because the available actions delineate the “specified System configuration". Furthermore, including the language in the standard and as a result in the RC's SOL Methodology, helps ensure the performance criteria in the Operations Horizon is not more limiting than the performance criteria used in the Near-term or Long-term Planning Horizons.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

ITC agrees with MEC and believes that addressing the fundamental concept of defining SOL Exceedance needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with the approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance and reacting to it by initiating an Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

The FAC standards should facilitate the creation of SOL's, not define operating criteria. SOL's should; (1) at a minimum be equal to Facility thermal or voltage limits and (2) consider system stability (voltage or transient) limits that may require limits more restrictive than Facility thermal or voltage limits.

The FAC standards should in no way infer that dynamic analysis needs to be performed as part of RTAs. Requirement R6 of FAC-011-4 as currently written could be inferred to require real time dynamic analysis. Specifically, it is unclear if requirements R6.1.3, R6.2.3, R6.3 and R6.4 require that RTA's include dynamic analysis to determine if Instability would occur or if operating to the pre-identified SOL's would provide this determination.

ITC agrees with MEC that the phrase "could be executed and completed within the specified time duration" throughout requirement R6. This could be interpreted as requiring a timing analysis before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate. The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources.

Instability, as used throughout the existing standards is an undefined term which leaves room for broad interpretation. This term should be removed or defined to clarify that single unit instability would not constitute "instability" as it is used in these proposed standards.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	

Comment

Texas RE has concerns with the performance criteria specified in FAC-011-4 Requirement R6. As an initial matter, until FAC-014-3 Requirement R6 is read, it isn’t understood that the performance criteria in FAC-011-4 R6 is referring to SOL exceedances.

That said, Texas RE is concerned that the way the performance criteria is written, and that an SOL exceedance would not occur until the highest Emergency Rating is exceeded. Therefore, the RC and TOP may not develop an Operating Plan for exceedances of the Normal Rating identified through the OPA (TOP-002-4 and IRO-008-2), and would not be required take action to return flow to Normal Ratings when Real-time flows exceed the Normal Rating (TOP-001-4), since there is no exceedance occurring in the Parts 6.1 and 6.2 scenarios:

- FAC-011-4 Part 6.1 - Operating Plans should be created anytime the anticipated pre -Contin demonstrates flow above the normal Rating or voltage outside of the normal System Voltage Limits. Additionally, Operating Plans should be initiated when the actual pre -Contingency state normal Rating.
- FAC-011-4 Part 6.2 should still require entities to create an Operating Plan that is available to System Operators if evaluation of potential single Contingencies listed in Part 5.1.1 against the anticipated pre -Contingency state (ow above normal Ratings. There is no way to know if System adjustments could be executed within time duration of Emergency Ratings without creating an Operating Plan to address the issue, and identifying a time-frame in which the Operating Plan could be executed. Since FAC-014-3 R6 states determination of SOL exceedances during the OPA is required to be in accordance with RC SOL Methodology, this language would not require a the creation of an Operating Plan to mitigate an exceedance of the normal Rating that is identified during the OPA.
- Real-time flows may legitimately exceed Normal Ratings as a result of conditions unanticipated by OPA, initiating the use of Emergency Ratings and their associated time limits in order to return flows to below Normal Ratings without an Operating Plan. This is the intended purpose of Emergency Ratings. It is unrealistic to assume that all operating conditions are captured by OPA, as OPA is based on preconceived contingent states.
- The same does not hold true for “anticipated pre-Contingency states” based on OPA. An anticipated pre-Contingency overload beyond the Normal Rating indicated by OPA is a base case overload which requires mitigating actions or an Operating Plan before the condition which would cause the overload occurs. Using Emergency Ratings and their associated time limits for this situation is not their intended purpose.

RCs and TOPs should be prepared when flow is outside of Normal Ratings. In order to maintain reliability, Texas RE recommends immediate action through the use of an Operating Plan to mitigate any flows or voltages outside the Normal ratings or System Voltage Limits.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No

Document Name	

Comment

Southern California Edison (SCE) believes that the NERC Standard Drafting Team approach of defining SOL Exceedance through a performance criteria in Requirement 6 of FAC-011-4 is inappropriate. If the Standards Drafting Team decides to include the undefined term “SOL Exceedance” within the performance criteria of FAC-011-4, the SDT effectively exposes a number of TOPs and RCs to the risk of violating FAC-011-4 (Requirement 6) if/when exceedances of system operating limits occur either in RTA or OPA. SCE believes that NERC should mitigate the regulatory uncertainty of using the undefined terminology within the performance criteria of FAC-011-4, and create a standard definition of SOL Exceedance. SCE is particularly sensitive to this issue due to Peak RC ceasing operations in 2019.

Additionally, SCE believes NERC should create a definition for “SOL Exceedance” by using existing framework of IRO and TOP standards. SCE believes that the present context of defining what constitutes SOL exceedance and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

Finally, SCE supports the examples presented by MidAmerican and the MRO NSRF that demonstrate the unintended consequences of using the undefined term “SOL Exceedance” within FAC-011-4 Requirement R6.

Likes 0	
Dislikes 0	

Response

Randy MacDonald - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Does planned load shedding include automatic load shedding schemes such as UVLS? Within the operational time frame UVLS should be allowed.

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

In 6.1.1 and 6.1.2, use of emergency ratings and emergency voltage limits seems inappropriate during pre-contingency states. Recommend re-phrasing 6.1.3 and 6.2.3 to "a state that leads to instability, uncontrolled separation, or Cascading" in order to be more consistent with existing definitions, such as IROL and Reliable Operation, that use the terms instability, uncontrolled separation, and Cascading.

Likes 0	
Dislikes 0	

Response

William Sanders - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment

In 6.1.1 and 6.1.2, use of emergency ratings and emergency voltage limits seems inappropriate during pre-contingency states. Recommend re-phrasing 6.1.3 and 6.2.3 to "a state that leads to instability, uncontrolled separation, or Cascading" in order to be more consistent with existing definitions, such as IROL and Reliable Operation, that use the terms instability, uncontrolled separation, and Cascading.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

On behalf of our City Light SME: The criteria seems appropriate and in line with TPL criteria.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

We are in general agreement over the proposed changes as they essentially maintain the system performance criteria, similar to the approach in the currently effective FAC standards. Our main comments are:

- **The proposed standards should require the Reliability Coordinator's (RC) methodology to establish stability limits when those limits also impact other RC Areas, and that the criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied.**

- **Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognized that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. However, this falls short of requiring an entity to determine new/revised limits to begin with. Without knowing the boundaries, performing real-time analysis every 30 minutes does not give the entity an indication if current operations (power flow or voltage levels) exceed the limits that are valid and applicable for the present conditions. These conditions pose unacceptable risks of instability since the operator does not know whether the next contingency will result in system instability.**

We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	Yes
Document Name	

Comment

GTC agrees with the SDT's proposal and has one suggested wording modification the Requirement R6, Part 6.2.1.

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided

that System adjustments could be executed and completed within the

specified time duration of those Emergency Ratings. Flow through a

Facility must not be above the Facility's highest applicable Emergency Rating.

Likes 0	

Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower

Answer	Yes
Document Name	

Comment

We are in general agreement over the proposed changes as they essentially maintain the system performance criteria, similar to the approach in the currently effective FAC standards. Our main comments are:

· The proposed standards should require the Reliability Coordinator's (RC) methodology to establish stability limits when those limits also impact other RC Areas, and that the criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied.

· Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognized that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of an RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. However, this falls short of requiring an entity to determine new/revised limits to begin with. Without knowing the boundaries, performing real-time analysis every 30 minutes does not give the entity an indication if current operations (power flow or voltage levels) exceed the limits that are valid and applicable for the present conditions. These conditions pose unacceptable risks of instability since the operator does not know whether the next contingency will result in system instability.

We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

We support the FAC revisions.

We have the following comments:

Subrequirements R7.1 andR 7.2

We agree with comments submitted by the NPCC RSC in regards to requirements 7.1 and 7.2. The subrequirements R7.1 and R7.2 require the identification of SOL that are IROL and the criteria for identifying SOL violations that are IROL. We do not understand the difference and our compliance department do not see how the evidence of those two subrequirements would be distinct.

Requirement R5.1

We have a minor comment regarding the addition in R5.1 of "Specify the" makes the use in 5.1.1 of "any" more ambiguous than it is in the current version. Consider that R5 now requires

a) identify in its SOL methodology…

b) Specify the following single contingency event…

c) Loss of "any" of the following.

Before it clearly "included" the following "list" of single contingency events. It would be better for the language to clearly state in 5.1.1. "Loss of each of the following" or return to language that clearly mandates the inclusion of the loss of all the listed elements.

Requirement 9

Also, the last sentence of the Rationale for Requirement R9 for FAC-011-4 should be modified as follows.   "(…) mandates provision of the SOL Methodology to non-adjacent RCs [or to adjacent RCs in another Interconnection] that have specifically requested (…)"

Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SCE concurs with MidAmerican's additional comments regarding FAC-011-4.	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
Regarding R3.3 What is the purpose of this subrequirement? The methodology should not prevent or limit the use of undervoltage load shedding by	

the Reliability Coordinator in the operational time frame. Suggest changing the wording to allow for undervoltage load shedding within the operational time frame as long at the reliability coordinator is aware. The methodology could have the requirement that the use of UVLS requires RC approval.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Numbering typos exist in Measure Nos. M7, M8, and M9. Requirement Nos. R7, R8, and R9 should be referenced accordingly.

Revised language in Requirement R1 is not included in the Violation Security Levels table. Specifically, the term “documented” was added to Requirement R1. ERCOT suggests including the term in the Violation Severity Levels table order to be consistent.

Similarly, the revised language in Requirement R2 is not included in the Violation Security Levels table. Specifically, “the applicable” was replaced with “which” and “are” in Requirement R2. ERCOT suggests including the same revisions in the Violation Severity Levels table.

In requirement R9, “and any changes to the SOL Methodology prior to the effective date of the SOL Methodology” was deleted. ERCOT suggests aligning the Violation Severity Levels table to align with this revision and the specific language of the applicable requirements. For Part 9.1, there is no distinction between “new or revised” in the wording of the requirement, but it is explicitly stated in the Violation Severity Levels table.

ERCOT suggests capitalizing “methodology” in Requirement R9, Part 9.2.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed FAC-011-4 Part 3.3 uses the term “under voltage” while the NERC Glossary and other Standards use the term “undervoltage”.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

Requirement R2 specifically states that the RC “shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations”. This requirement needs to be bounded such that the RC is not specifying in its methodology how a Transmission Operator and thus a Transmission Owner is required to rate its transmission facilities, up to and including the use of real time ratings. This would determine the amount of risk a Transmission Owner is subject to for its facilities. The standard should only specify the end objective and not the process to achieve that objective.

Requirement R8 is redundant with IRO-010-2 R1. SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R8 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	
Document Name	

Comment

FMPA is concerned that Project 2015-09 does not consider the work done by the MEITF (Methods for Establishing IROLs Task Force). There are defined terms used in R6 that the MEITF has proposed changes to, and that have been endorsed by the NERC PC and OC. FMPA asks that the implementation plan be changed so that FAC-011-4 would only be effective once the new definitions proposed by the MEITF become effective

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

ATC does have other comments on FAC-011-4:

- Requirement R3 addresses the establishment of a voltage-based SOL at each bus. No similar requirement is given for thermal ratings. It is unclear if the SDT expects each Facility to have a thermal-based SOL. Alternatively, can TOPs and RCs use multi-element or proxy flowgates to manage power flow on the system? The expectation regarding thermal related SOLs needs to be clearly stated in any requirement such that entities can fulfill the requirements and all entities are operating the BES from the same understanding.

- R3.3 should be improved by clarifying what undervoltage load shedding (UVLS) systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by UVLS relay settings implemented by a distribution utility or an end-use customer. A suggested edit is to clarify these are BES systems as follows: *"in-service BES relay settings for undervoltage load shedding…"*.

- Similar to comments provided in question #1 related to R6.5, Requirement R4.7 should be modified to remove the restriction on using UVLS Programs when setting stability limits. It is generally accurate to state that UFLS should not be relied upon to maintain stability, although the SDT needs to recognize that UFLS may be a necessary component to maintain stability of a portion of a system deliberately islanded by a Remedial Action Scheme. As such, R4.7 should be modified to read, *"State that the use of underfrequency load shedding (UFLS) programs are not allowed in the establishment of stability limits except in specific, documented circumstances (e.g., Remedial Action Schemes)."*

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli

Answer	
Document Name	

Comment

R3.3 Require that System Voltage Limits are higher greater than or equal to in service relay settings for under voltage load shedding (UVLS) relay settings systems and Undervoltage Load Shedding Programs

R3.3 should be improved by clarifying what under voltage load shedding systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by under voltage load shedding relay settings implemented by a distribution utility or an end-use customer

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower

Answer	
Document Name	

Comment

We offer the following specific comments:

Sub-Requirement R4.1.3:

It is not clear what is meant by “unit” stability. We suggest reverting back to using the current term “angular” stability as it is a term well understood by the industry.

Sub-Requirement R4.3:

A main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Sub-Requirement R4.3 to establish SOLs that impact on the Interconnection:

“Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology.”

Sub-Requirements R5.2 and R5.3

Sub-Requirements R5.2 and R5.3 require the RC to identify any additional single or multiple Contingency events. We believe that specifying, at a minimum, which contingencies must be respected (similar to Sub-Requirement R5.1.1. for single Contingencies) would improve reliability. In particular, to the extent there is an alignment in respecting the same set of contingencies and performance criteria for IROLs.

Furthermore, the loss of small or radial portions of the system should be acceptable provided the performance requirements are not violated for the remaining bulk power system.

Sub-Requirement R6.2.2

Sub-Requirement R6.2.2 should include the same wording as sub-requirement 6.1.2:

“Voltages are within normal System Voltage Limits; however, emergency

System Voltage Limits may be used when System adjustments to return

the voltage within its normal System Voltage Limits could be executed

and completed within the specified time duration of those emergency System Voltage Limits.”

Sub-Requirements R6.3 and R6.4

For consistency purposes, we recommend that Sub-Requirements R6.3 and R6.4 also require to demonstrate that flow through Facilities are within Normal Ratings, similar to Sub-Requirements 6.1.1 and 6.2.1:

“Flow through Facilities are within Normal Ratings; however, Emergency

Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.”

Sub-Requirements R7.1 and 7.2

Sub-requirements R7.1 and R7.2 require to describe how to identify IROLs, and to identify the criteria for IROLs which is basically the same thing. We recommend merging these sub-requirements into one:

7.1. A description of the criteria to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs) and for developing any associated IROL Tv.

R3

Sub-Requirement 3.5 combines two requirements, (1) require a method for determining… and (2) require common use.   Sub-Requirement 3.5 should be re-written as “require a method for determining…” as shown below.

We assume that 3.6 and 3.7 intend to “address coordination” within the “method for determining” the limit. As such, that consideration should be rolled into the requirement for “a method for determining..”

Since System Voltage Limits are SOLs, it is unnecessary to explicitly require the operation within the restrictions of System Voltage Limits. Also it is inappropriate to place any system operation requirement (Require the use…) within an operating parameter development methodology. There are already requirements for the system to always be studied and operated within the SOL restrictions of the local reliability entity as well as the SOL of adjacent reliability entities. All requirements for “require the use of common” should be deleted.

3.5 Provide the method for determining the common System Voltage Limits in coordination with adjacent Reliability Coordinators and Transmission Operators.

R4

What is the point of R4.2? If R5 requires that all stability analysis to evaluate the contingencies listed in “5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs.” How can one violate 5 without also violating 4.2? Is this not double jeopardy? The identical requirements are applied to both general SOL stability analysis and OPA/RTA stability analysis.   R4.2 is a requirement to comply with R5.1.

Sub requirements 5.3 and 5. 4 are double jeopardy and should be deleted. How can there be any contingencies used “determining the stability limits to be used in operations” that are not completely identical to the contingencies used in “determining stability limits and performing OPAs and RTAs.” It is impossible to violate 5.3 or 5.4 without simultaneously violating 5.2

We suggest the SDT Re-write 4.2 determining the stability limits to be used in operations as follows and eliminate R5 its entirety.

4.2 Specify the following single Contingency events for use in determining stability limits

4.2.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

• generator;

• transmission circuit;

• transformer;

• shunt device; or

• Single pole block, with Normal Clearing, in a monopole or bipolar high voltage direct current system.

4.2.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real -time Assessments.

R5

What is the point of R5.2? If 5.2 requires that all stability analysis to evaluate the contingencies listed in “5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs.” How can one violate 5.1 without also violating 4.2? Is this not double jeopardy? The identical requirements are applied to both general SOL stability analysis and OPA/RTA stability analysis.   R4.2 is a requirement to comply with R5.1.

Sub requirements 5.3 and 5. 4 are double jeopardy and should be deleted.   It is impossible to violate 5.3 or 5.4 without simultaneously violating 5.2

Re-write 4.2 as follows and eliminate R5 its entirety.

4.2 Specify the following single Contingency events for use in determining stability limits

4.2.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

• generator;

• transmission circuit;

• transformer;

• shunt device; or

• Single pole block, with Normal Clearing, in a monopole or bipolar high voltage direct current system.

4.2.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real -time Assessments.

Likes 0	
Dislikes 0	

Response

Laura McLeod - NB Power Corporation - 5

Answer	
Document Name	

Comment

Do not agree with R3.3, too restrictive. Should be allowed to have UVLS relays set higher then SOL voltage limits.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment	
R5.1.1 includes all generators and all shunt devices. There is minimal benefit to attempting to study the impact of the unavailability of every shunt device on the transmission system. Defining some criteria on which shunt devices will be studied would be ideal, to avoid creating an unnecessarily burdensome requirement for studies being performed. RCs should specify their criteria for including these, recognizing the size and potential impact of individual elements, the design of system protection, and the needs of their area.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	

Comment

Recommendation: Replace “Instability” with “System instability”

Proposed FAC-011-4. The companies suggest replacing “instability” with “System instability” to provide context and boundaries to the proposed Requirements.

The companies recognize the word “instability” is used without a modifier in the NERC Reliability Standards and Glossary Terms but equally so, it is used with a modifier to provide a boundary to the word. For example:

- Glossary Term: ULVS Shedding Program, “…leading to voltage instability, voltage collapse…”
- Glossary Term: Adverse Reliability Impact, “…an event that results in frequency-related instability…”
- TPL-001-4 R6, “…system instability…voltage instability…”
- PRC-012-2 R4.1.3, “…angular instability, voltage instability…”
- PRC-024-2 R1, “…instability in power conversion…”

Significant Administrative Burden. The effect of using “instability” without a modifier will require entities to report every single instance of “instability” developed from a significant number of contingency events identified during the annual Planning Assessments, including unit instability under TPL-001-4.

Recommendation 1

Replace “instability” with “System instability” throughout the proposed FAC-011-4 revision. “System instability” is already used in TPL-001-4. Replacing the term provides an effective parameter to reporting by requiring reporting of coordinated instances of instability that necessitate a Correction Action

Plan and, in turn, relieve entities of a time-consuming and overly-burdensome reporting requirement.

Recommendation 2

Requirements 6.1.3 and 6.2.3

The companies suggest 30-minute time thresholds, Tv, be added to the proposed revisions to FAC-011-4 R6.1.3 and R6.2.3. This provides RCs / TOPs a time certain threshold to correct exceedance for determinations of compliance.

R6.1.3 and R6.2.3 refer to preventing instability, cascading or uncontrolled separation.

- The present definition of IROL Violation has a Tv time threshold (< 30 minutes) before it becomes a compliance issue.
- The proposed language does not recognize time-frames associated with exceedances of established stability limits.
- Effect: Without a time-frame, it is conceivable a system could experience a significant number of exceedances that possibly last less than 1-minute with a magnitude less than 1%. In such a case, to report would be an onerous compliance burden.

To mitigate potentially over burdensome reporting of a significant number of *di minimis* exceedances, the companies recommend establishing a parameter by requiring reporting of only coordinated instances of instability that necessitate a Correction Action Plan.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase 2 of this project. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment
NV Energy understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance. However, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. Due to reasons that we outlined in response to the question 1 (see above) we find it inappropriate to incorporate the definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard and significantly worse and more risky in comparison with coming up with definition of SOL Exceedance**.** NV Energy shares the industry concern that the proposed changes to Standards FAC-011-4 and FAC-014-3 would cause the following unintended consequences and repercussion: • If approved, new versions of the NERC Standards FAC-011-4 and FAC-014-3 **would expose a large number of TOPs and RC to the SIGNIFICANTLY increased compliance risk (direct violation of the FAC-014 R6 in conjunction with FAC-011-4 R6) unless enormous resources and efforts are added within each TOP's/RC's organization.** • **If the interpretation is correct that TOP/RC would not violate FAC standards in case of exceeding performance criteria as long as they implement their Operating Plan (per TOP-001 R14), our above mentioned concern transforms into another concern about huge administrative, compliance related, burden. Namely, TOP/RC would have to have** (as evidence of compliance), logging and recording documentation that it implemented its Operating Plan in response **to each and every instance when projected post-contingent flow on RTCA exceeds highest emergency rating, even for short time period (such as several minutes).** • Therefore, due to the absence of time-frame considerations for exceedances of projected post-contingent flows or voltages, the new versions of the NERC Standards FAC-011-4 and FAC-014-3 would cause frequent SOL exceedances (and therefore frequent violations of the new FAC-011 performance criteria) and prohibitively costly and time consuming administrative burden. • **This definition may decrease reliability as opposed to the SDT's intention of increasing reliability, because of the overwhelming pressure on transmission operators and reliability coordinators to record and communicate frequent SOL exceedances as opposed of being focused on monitoring and implementing control actions to maintain system reliability in real-time.** • We believe the definition would **delay implementation of the Operating Plan in real-time** due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today. • We believe that another unintended outcome would be operation **in an unnecessarily conservative state, as TOP would have to operate with higher reliability margin from the highest emergency rating, to ensure that following a forced outage or other system disturbance, that the next execution of real-time contingency analysis would not show any facility beyond its highest emergency thermal rating or emergency voltage rating**

- **The proposed standards would significantly constrain the business in the industry** as conservative limits would **not allow for many of scheduled outages to proceed** without risk of SOL exceedance/performance criteria violation.

We re-iterate our ***recommendation that SDT re-considers adoption of the performance criteria/SOL exceedance per above mentioned suggestions.*** We believe that these modifications would provide the following benefits:

- They are *more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
- *They would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
- They would provide *comparably reliable operation* of power systems.
- They are *based on physical limitations of various components of transmission facilities*.
- They would *prevent potentially huge increase of cost* of market operations.
- They provide *more clarity and avoid ambiguity and interpretation issues*.

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	

We believe R1 should be the only requirement in FAC-011-4. The SDT can accomplish their goal by having Requirement R1 that requires an entity to cover the performance criteria within a newly created appendix. There are 9 requirements and approximately 34 sub-parts in FAC-0011 that increases compliance risk without commensurate benefits to reliability.

Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	Proposed text for FAC-011-4 R5, R6, and R7.docx
Comment	

a. Stability Limit should be capitalized as it is a defined term

b. The wording of FAC-011-4 R5 implies that stability studies are required for OPAs and RTAs. This would be a new requirement and does not correspond with the SDT's intent. We suggest the edits to R5 shown in the attached WORD document to clarify that stability studies are not needed for OPAs and RTAs, but, rather, stability limits derived by other studies need to be respected in OPAs and RTAs.

c. Please clarify the need for the word "potential" in R6 as the word is not used in other places, such as the TPL standards, where single contingencies are also referred to without the word "potential." We suggest the following language to R6 and R7.

d. The word "potential" is not used elsewhere to modify contingencies, which are, by their nature, "potential." For example, in the TPL standards, single contingencies are referred to without the word "potential." For this reason, AZPS recommends that the SDT clarify the need for inclusion of the word "potential" in R6. If such need is not identified, AZPS suggests the following language to R6 and R7. Further, AZPS notes that performance criteria is established in Requirement 6.1 as well as in FAC-014, requirement R6. For this reason, its inclusion in Requirement R6.3 appears redundant. AZPS recommends deletion as set forth below. Finally, AZPS recommends consistency when referring to the operation of the BES within SOLs. For this reason, AZPS recommends replacing "violating" with "exceeding" in Requirement R7.

e. The wording of FAC-011-4 R6.1.3 and R6.2.3 seems to imply that dynamic studies are required for OPAs and RTAs. This would be a new requirement and does not correspond with the SDT's intent. AZPS also suggests adding the word "widespread" under R6.1.3 and R6.2.3 to exclude local area instability or instability of a small generator. We suggest the following edits to R6 to clarify that dynamic studies are not needed for OPAs and RTAs, but, rather, stability limits derived by other studies need to be respected in OPAs and RTAs.

f. As written, FAC-011-4 R6.1.1 and R6.2.1 leaves the burden of proof on the TOP to be able to demonstrate that the operating actions can be taken within the appropriate time of the Facility Rating which is a very difficult and extensive task.

g. Regarding R6.2.1, if RTCA shows that emergency ratings are exceeded, there should be a recognized time frame in which to correct the problem prior to it becoming a compliance issue. As written, the proposed definition does not recognize a time-frame associated with exceedances of the facility's highest emergency rating. If not recognized, this could lead to a large volume of inconsequential exceedances such as those less than one minute and have magnitude of less than one percent.

h. AZPS suggests R6.1, R6.2, and R6.3 be broken into two separate sub-requirements: one related to Real-time monitoring and Real-time Assessment, and one related to Operational Planning Analysis.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	

Comment

This standard in its current form allows a single entity the ability to dictate operating and effectively planning criteria. PNM believes that the development of the SOL methodology should be a joint effort including RCs, TOPs, and PAs.

PNM believes R2 gives the RC that ability to dictate how an entity uses its own Facility Ratings effectively modifying FAC-008. PNM agrees the requirement does not specifically change, limit, or modify Facility Rating determined by the equipment owner; however, there is no point for an entity to establish a Facility rating that can't be used when operating the system. PNM recommend removal of R2 and revision of FAC-008-3 to address any concerns regarding the coordination of Facility Ratings.

PNM questions the reliability basis of R3.3. PNM believes that there may be reasons to have the UVLS setting higher than the limits for certain critical contingencies. FERC order No. 818 specifies not using UVLS for N-1; however, this requirement doesn't have that qualifier. If the SDT feels this concept should be included in the standard that requirement should move under R4.6 and shall clearly specify that it is only applicable to single contingencies.

Likes 0	
Dislikes 0	

Response

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	
Document Name	

Comment

Entergy supports the comments submitted by MidAmerican Energy Company.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	
Document Name	

Comment

The construct of the current active version, FAC-011-3, makes for a lengthy RSAW response with respect to Requirements that lump all SOL types (thermal, voltage, stability) into a single Requirement. The SDT efforts to split these types up into their individual areas, should make for a much more consistent, focused & streamlined RSAW, appreciated by both the Applicable Functional Entity, and their incoming audit teams alike.

For the SDT's consideration

In all areas (Standard, Rationale, Mapping, etc.)

- R3.1 "Reliability Coordinators" should be either "Reliability Coordinator" or "Reliability Coordinator's"; (Note: Given that R3 is talking about the RC SOL Methodology, one could argue that the full reference to the RC SOL Methodology again in R3.1 is duplicative, and could be replaced with "Methodology");
- R5: Repetitive language around determining stability limits and performing OPA & RTA could be remedied for greater clarity by splitting into one requirement focused on stability limits and one requirement focused on OPA & RTA. Otherwise, to stick to the same structure you have for

R5.1, R5.2 & R5.3 could be merged into one sub-requirement.

- R8: Inconsistency between Standard language. “Reliability Coordinator.” vs “Reliability Coordinator(s).”
- M7, M8, M9: Incorrect references to M6, M7 & M8 respectively.

The rationale document for FAC-011-4 has the following typos:

- R3.1 “specificall” should be “specifically”
- R6.1.1 “normal rating” should be capitalized “Normal Rating”
- R8 Rationale discusses R7, when it’s referring to R8.

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

No response.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	
Document Name	

Comment

NIPSCO is in MISO and it appears that the prescribed performance criteria here will change the MISO SOL exceedance methodolgy that we presently operate under for TOP-001 R14 and R15. This may be a concern.

We were triple-booked for the related 2015-09 informational webinar. We were hoping to view the streaming replay but never saw it posted. We inquired and were told it would soon be posted but never saw it. Please post promptly next time if possible. Thanks.

Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA believes Requirement 3.5 should be modified for clarity: change “provide” to “define.” ”*Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and “define” the method for determining the common System Voltage Limits to be used in Operations.”*

BPA believes that in Requirement 4.1.3, the term should remain “angular stability” as this is industry standard. “Unit stability” is not a defined term and is not as understood as angular stability.

BPA recommends consolidating requirements 5.2 and 5.3 and requirements 6.3 and 6.4 to make it so an RC may specify additional single or multiple Contingency events or types of Contingency events for use in determining stability limits and performing OPAs and RTAs. BPA does not support the RC being allowed to specify two additional lists (as allowed by 5.2 and 5.3 when not consolidated) of single or multiple Contingency events or types of Contingency events because BPA believes this could complicate the RC’s SOL Methodology without benefiting reliability. If there is a reliability benefit, BPA would like to request the SDT include that in the White Paper.

BPA proposed edits:

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits and performing OPAs and RTAs.

Delete 5.3

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre -
Assessments) and anticipated pre Contingency state (Ope or uncontrolled
separation does not occur.

Delete 6.4

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MidAmerican Energy Company (MEC) understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance. However, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. Due to reasons that we outlined in response to the question 1 (see above) we find it inappropriate to incorporate the definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard and significantly worse and more risky in comparison with coming up with definition of SOL Exceedance**.**

MidAmerican believes that the proposed changes to Standards FAC-011-4 and FAC-014-3 would cause the following unintended consequences and repercussion:

- If approved, new versions of the NERC Standards FAC-011-4 and FAC-014-3 would expose a large number of TOPs and RC to significant increased compliance risk (direct violation of the FAC-014 R6 in conjunction with FAC-011-4 R6) unless enormous resources and efforts are added within each TOP's/RC's organization.
- If the interpretation is correct that a TOP/RC would not violate FAC standards in case of exceeding performance criteria as long as they implement their Operating Plan (per TOP-001 R14), our above mentioned concern transforms into another concern about huge administrative, compliance related, burden. Namely, TOP/RC would have to have (as evidence of compliance), logging and recording documentation that it implemented its Operating Plan in response to each and every instance when projected post-contingent flow on RTCA exceeds highest emergency rating, even for short time period (such as several minutes).
- Therefore, due to the absence of time-frame considerations for exceedances of projected post-contingent flows or voltages, the new versions of the NERC Standards FAC-011-4 and FAC-014-3 would cause frequent SOL exceedances (and therefore frequent violations of the new FAC-011 performance criteria) and prohibitively costly and time consuming administrative burden.
- This definition may decrease reliability as opposed to the SDT's intention of increasing reliability, because of the overwhelming pressure on transmission operators and reliability coordinators to record and communicate frequent SOL exceedances as opposed of being focused on monitoring and implementing control actions to maintain system reliability in real-time.
- The definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today.
- Another unintended outcome would be operation in an unnecessarily conservative state, as TOP would have to operate with higher reliability margin from the highest emergency rating, to ensure that following a forced outage or other system disturbance, that the next execution of real-time contingency analysis would not show any facility beyond its highest emergency thermal rating or emergency voltage rating
- The proposed standards would significantly constrain the business in the industry as conservative limits would not allow for many of scheduled outages to proceed without risk of SOL exceedance/performance criteria violation.

The SDT should reconsider adoption of the performance criteria/SOL exceedance per above mentioned suggestions, which are in accordance with current definition of SOL exceedance that is in effect in MISO Reliability footprint. These modifications would provide the following benefits:

- They are *more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
- *They would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
- They would provide *comparably reliable operation* of power systems.
- They are *based on physical limitations of various components of transmission facilities*.
- They would *prevent potentially huge increase of cost* of market operations.
- They provide *more clarity and avoid ambiguity and interpretation issues*.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	
Document Name	

Comment

OKGE supports the comments provided by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

We offer the following specific comments:

Sub-Requirement R4.1.3:

It is not clear what is meant by "unit" stability. We suggest reverting back to using the current term "angular" stability as it is a term well understood by the industry.

Sub-Requirement R4.3:

A main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Sub-Requirement R4.3 to establish SOLs that impact on the Interconnection:

"Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirements R5.2 and R5.3

Sub-Requirements R5.2 and R5.3 require the RC to identify any additional single or multiple Contingency events. We believe that specifying, at a minimum, which contingencies must be respected (similar to Sub-Requirement R5.1.1. for single Contingencies) would improve reliability. In particular, to the extent there is an alignment in respecting the same set of contingencies and performance criteria for IROLs.

Furthermore, the loss of small or radial portions of the system should be acceptable provided the performance requirements are not violated for the remaining bulk power system.

Sub-Requirement R6.2.2

Sub-Requirement R6.2.2 should include the same wording as sub-requirement 6.1.2:

"Voltages are within normal System Voltage Limits; however, emergency

System Voltage Limits may be used when System adjustments to return

the voltage within its normal System Voltage Limits could be executed

and completed within the specified time duration of those emergency System Voltage Limits."

Sub-Requirements R6.3 and R6.4

For consistency purposes, we recommend that Sub-Requirements R6.3 and R6.4 also require to demonstrate that flow through Facilities are within Normal Ratings, similar to Sub-Requirements 6.1.1 and 6.2.1:

"Flow through Facilities are within Normal Ratings; however, Emergency

Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings."

Sub-Requirements R7.1 and 7.2

Sub-requirements R7.1 and R7.2 require to describe how to identify IROLs, and to identify the criteria for IROLs which is basically the same thing. We recommend merging these sub-requirements into one:

7.1. A description of the criteria to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs) and for developing any associated IROL Tv.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

No

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	
Document Name	

Comment

1. R 4.1.3: why SDT used “unit stability” instead of “angular”? We believe it is better to match the language in PRC-26 R1.
2. R.4.7: We would recommend revising the requirement R4.7 to state that the use of UFLS and UVLS is not allowed in the establishment of stability limits for the single contingencies identified in R5.1.1.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

The MRO NSRF does have other comments on FAC-011-4:

- R3.3 should be improved by clarifying what undervoltage load shedding (UVLS) systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by UVLS relay settings implemented by a distribution utility or an end-use customer. A suggested edit is to clarify these are BES systems as follows: *"in-service BES relay settings for undervoltage load shedding…"*.
- Similar to comments provided in question #1 related to R6.5, Requirement R4.7 should be modified to remove the restriction on using UVLS Programs when setting stability limits. It is generally accurate to state that UFLS should not be relied upon to maintain stability, although the SDT needs to recognize that UFLS may be a necessary component to maintain stability of a portion of a system deliberately islanded by a Remedial Action Scheme. As such, R4.7 should be modified to read, *"State that the use of underfrequency load shedding (UFLS) programs are not allowed in the establishment of stability limits except in specific, documented circumstances (e.g., Remedial Action Schemes)."*

We also support the recently developed SAR, submitted as a result of phase 1 of the Standards Efficiency Review project, to retire many non-essential or redundant requirements. To reduce the need for a similar effort in the future, the MRO NSRF requests the SDT to consider if Requirement R8 is sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it’s essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators, which should remove the need for R8. If kept, there may be overlapping compliance obligations with two requirements for the same activity.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	
Document Name	

Comment	
R3.1 introduces ambiguity and potential inconsistency by allowing the Reliability Coordinator to decide whether to require that a BES bus/station have an associated System Voltage Limit without also requiring any sort of technical rationale or criteria. If the intent of R3.1 is to address a specific issue, LES recommends the drafting team clarify their intent within the requirement. R3.2 is confusing and unnecessary with an in-place definition of System Voltage Limit. As written, R3.2 appears to provide two different methods for an entity to determine voltage limits. R3.3 should state: "Require that **the upper (or higher)** System Voltage Limits…" for improved clarity. R3.4 should be removed in consideration that the definition of System Voltage Limit already requires a "minimum steady-state voltage limit". Combining the language from the definition and R3.4 would essentially read "Identify the lowest allowable minimum steady-state voltage limit…" LES is concerned that R2 does not provide adequate assurance that the RC will respect the Facility Ratings established by the TO or the TO's FAC-008 methodology. As written, the language is vague and appears to allow the RC to determine the Facility Ratings that a TO must use. Also, based on the NERC definition of Facility Rating, there is a potential conflict between System Voltage Limits and Facility Ratings as both could utilize voltage ratings. These conflicts between FAC-011-4 and FAC-008-3 and the definition of Facility Rating need addressed.	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
With respect to R5.4, requiring Reliability Coordinators to identify Contingency events to use in determining stability limits for the Near Term Planning Horizon (FAC-015-1 R4) which also includes 5-year horizon is added burden to both Reliability Coordinators and the Planning Coordinators/Transmission Planners without added benefit. The drafting team should consider limiting this requirement to 0-1 year period which would be the most concerning for the Reliability Coordinators.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
No further comments	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
It is not clear what other additional single contingency events are there that are not already included in R5.1.1. Some guidance/criteria in selecting/identifying multiple contingency events (R5.2) for use in OPAs & Real-time Assessments would not only be helpful but ensure that the set of contingencies that meet basic minimum criteria are being evaluated.	
Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	
Document Name	
Comment	

Just a general comment on the use of the term "owner -provided Facility Ratings -011, FAC-014, and FAC-015. I believe this reference is referring to the FAC-008 Facility Ratings that TOs and GOs are required to determine and make available to various reliability entities. This may or may not be true. If it is true, any ambiguity could be eliminated by changing the reference to "Transmission Owner and Generator Owner provided Facility Ratings determined in accordance with FAC-008."

Please at least address the issue in the response to this comment especially if there is a different owner provided facility rating that these standards are referring to. Thanks.

Likes 0	
Dislikes 0	
Response	

3. The SDT acknowledges that requirement R6 could alternatively be located within a TOP or IRO standard; however, the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Proposed Requirement R6 was created to correspond with FAC-011-4 Requirement R6 in lieu of creating a definition for SOL Exceedance. Do you agree with Requirement R6?

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Subject to previous comments.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
However, we have the same comment as with Question 1: **Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state.** **We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.**	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes

Document Name	
Comment	
GTC understands this question to refer to FAC-014, Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Related to Proposed ***FAC-014-3*** Requirement R6, PJM has no additional comment.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Cowlitz PUD is not certain which standard requirement corresponds with Requirement R6 (should not be corresponding to itself), but agrees with detailed discriptions contained in a requirement rather than in a defined term. We affirm Proposed Requirement R6 created to correspond with FAC-011-4 (rather than in a TOP or IRO standard) is preferrable to creating a detailed, and complicated SOL Exceedance NERC Glossary term.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Southern believes that R6 should be a part of an operating standard in the IRO standard category.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees this information would be better suited in the TOP and IRO standards. The current approach requires understanding of how FAC-011-4 and FAC-014-3 fit together as they both refer to each other. It is confusing that the requirements must be read together, even though they reside in two different standards.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The wording of FAC-011-4 R6.1.1 and 6.1.2 is unclear. Words appear to be missing in the phrase “may be used when System adjustments to return the voltage…”. Reclamation recommends the SDT review R6.1.1. and R6.1.2 to ensure clarity.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
: PacifiCorp agrees with Requirement R6 except for the comments made in question 1.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP supports, in general, the proposed revisions to FAC-011, we believe additional clarity is needed within 6.1.3 to make it clear these obligations are only in reference to known stability limits and do *not* require TOP-provided, dynamic, real-time stability studies. While there are entities that do perform such real-time stability studies, this requirement should not impose that sort of analysis on *all* TOPs. AEP has chosen to vote negative on this revised standard driven by the current lack of clarity in this regard.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5

Answer	No
Document Name	

Comment

NPPD supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	

Comment

LES supports the comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF is not clear if the question is addressing FAC-014-3 R6, but we believe it is. Although we understand the SDT's intent of placing R6 in FAC-014-3, it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement. For example, TOP-001-4 requires an RTA to be performed by the Transmission Operator in requirement R13. The Transmission Operator is required to examine both the pre-Contingency and post-Contingency states based on the definition of Real Time Assessment. By creating FAC-011-3 R5 and R6, the SDT has adequately covered what Contingencies need to be evaluated to identify or monitor SOLs as part of RTAs and OPAs. Similarly, we believe the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10 and TOP-002-4 R1 adequately address the SDT's concern and language of proposed FAC-014-3 R6.

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	No
Document Name	

Comment

As stated, in Q1 NRECA does not agree with the proposed R6. NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to include a review of the TOP and IRO standards.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comments provided by NRECA.

As stated, in Q1 NRECA does not agree with the proposed R6. NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to include a review of the TOP and IRO standards.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends that FAC-011-4 R6 (6.3 and 6.4) be consolidated. With this edit (see BPA's response to question 2 above) BPA supports FAC-011-4 R6.	
Likes 0	
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
Additional, patient efforts by the SDT to develop a flexible definition of SOL exceedance is a superior approach versus a FAC-011 and FAC-014 performance requirement. The language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs. MidAmerican shares the MRO NSRF position regarding FAC-014-3 R6 that *"it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums*". General principles and good utility practice within the industry is to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint,. Consequently, all arguments presented in answering Questions 1 and 2 would apply and be of a significant concern to the TOPs.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
NIPSCO feels that R6 belongs in the TOP and IRO standards. We understand the SDT does not currently have access to these standards but that should not mean that this requirement is not placed in the appropriate standard. There will need to be a review of the TOP and IRO standard to place R6 in the appropriate place.	

Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not believe that the added requirements in Requirement R6 nor a definition for SOL Exceedance is necessary. Furthermore, CenterPoint Energy believes the SDT unnecessarily broadened the scope of the language by using the term “SOL exceedances” without additional focus on those exceedances that adversely impact the reliability of the BES. CenterPoint Energy recommends that the SDT clarify the intent of Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports the comments submitted by MidAmerican Energy Company.	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
No, AZPS is concerned that as proposed, requirement R6 of FAC-014-3 results in a redundancy that could result in ambiguity and confusion. For this reason, AZPS recommends that “SOL exceedance” be defined in FAC-014-3 R6, or FAC-014-3 R6 refers to FAC-011-4 R6 performance criteria instead	

of referencing "SOL exceedance."	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy shares industry concerns regarding FAC-014-3 R6 that *"it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums*". Furthermore, general principle and good utility practice within the industry is to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint,. Consequently, all arguments that we presented in answering Questions 1 and 2 would apply (and be of a significant concern) to TOPs. Please see all our comments and arguments above. In conclusion, if additional, patient efforts are done by SDT to formulate broad and flexible definition of SOL exceedance, the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
The SDT should consider revising the SAR to include modifications to TOP or IRO standards. The SDT should not go forward with Requirement R6 until they have reviewed TOP or IRO alternatives.	
Likes 0	
Dislikes 0	
Response	
Tommy Drea - Dairyland Power Cooperative - 5	

Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) supports the previous draft of FAC-011-4 and proposes the definition of SOL Exceedance should be retained. Removal of the SOL Exceedance definition and expanding FAC-011-4 Requirement R6 has resulted in FAC-011-4 becoming convoluted and confusing to interpret. The previous draft of FAC-011-4 in conjunction with the SOL Exceedance definition is less ambiguous and, therefore, produces a more desirable end result.	
Likes 0	
Dislikes 0	
Response	
Spencer Tacke - Modesto Irrigation District - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	
Comment	

We acknowledge the drafting team's question regarding the substance of R6 for FAC-014-3. We do not have any specific concerns regarding the language used. While we understand that the drafting team is not soliciting comment on where a requirement should reside, we would be remiss not to comment that this requirement is indeed out of place as proposed. The proposed R6 is a Real-time performance requirement surrounded by other requirements pertaining to methodology, and not the execution of said methodology. We understand that the SAR does not allow for an alternative approach at this time, but believe that this may need to be revisited at a later date.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	
Comment	

SAR Scope Issue

The companies believe the proposed revisions to FAC-014-3 R6 are, for all intents and purposes, incorporated into TOP-001 and TOP-002, and, as such, creates a potential conflict with Requirements in TOP-001 and TOP-002.

If that is the case, the proposed FAC-011-3 R6 revisions create a challenge to the SDT by basically requiring revision to TOP-001 and TOP-002 and, as such, the revisions fall outside the scope of the SAR.

Observation: SOL Exceedance Glossary Term

The companies would note, and we are confident the SDT is aware, TOP-001 and TOP-002 could be strengthened by a SOL Exceedance Glossary Term and the proposed R6 revisions do not eliminate the need for a SOL Exceedance Glossary Term.

Likes 0	
Dislikes 0	
Response	

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	

See comments to question 1. Because the SDT is not authorized to make changes to the TOP or IROs is not sufficient reason to place requirements in standards to which they don't belong. The performance criteria should rightly be debated and crafted in the context of system operations by a SDT with appropriate focus and expertise.	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Do not agree with 6.5, too restrictive. Should be allowed to apply non-consequential load loss.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	No
Document Name	
Comment	
However, we have the same comment as with Question 1: Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.	
Likes 0	
Dislikes 0	
Response	

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC is not clear if the question is addressing FAC-014-3 R6, but we believe it is given that the previous question asked for any further comments on FAC-011-4 and the next question asks for any further comments on FAC-014-3. Although we understand the SDT's intent of placing R6 in FAC-014-3, it is inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement. For example, TOP-001-4 requires an RTA to be performed by the TOP in requirement R13. The TOP is required to examine both the pre-Contingency and post-Contingency states based on the definition of Real Time Assessment. By creating FAC-011-3 R5 and R6, the SDT has adequately covered what Contingencies need to be evaluated to identify or monitor SOLs as part of RTAs and OPAs. Similarly, we believe the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10 and TOP-002-4 R1 adequately address the SDT's concern and language of proposed FAC-014-3 R6.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA supports the comments submitted by MRO. We would like to especially point to the concern that placing an operating requirement in a FAC standard goes against the effort of streamlining the standards currently underway with the Standards Efficiency Review.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment	
The criteria given are not clear as written such that they appear to occur in the Real-time horizon and apply to real-time operations rather than in the Operations Horizon as stated. As a consequence, the criteria do not seem to meet a methodology requirement but an operating one. Specifically, the identification of real-time monitoring and assessment as a demonstration is inappropriate for a FAC methodology requirement and belongs in TOP and IRO standards relating to operations. We believe there should not be an operating requirement in FAC-011 and in our opinion is a poor practice and should be shelved. The Standard "families" set certain expectations and should be respected because to do otherwise will create risks of inconsistency. If the TOP and IRO standards need amending, then amend them!	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC agrees with the MRO NSRF that it is not clear if the question is addressing FAC-014-3 R6, but we believe it is. Although we understand the SDT's intent of placing R6 in FAC-014-3, it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement. ITC agrees with MEC that if the SDT can formulate a broad and flexible definition of SOL exceedance, the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Without the option of modifying TOP and IRO standards to accommodate a SOL Exceedence definition, it is reasonable to add the performance criteria to FAC-011-4 R6. However, the language in R6 is unclear. While it is clear in 6.1 that we may exceed the Normal Rating without a contingency if we return to Normal within the Emergency Rating time duration, it is not clear in 6.2 that the system response (or anticipated system response) to a single contingency must be within Emergency Ratings. Similarly for 6.3, it is not clear that the criteria is for the system response to the contingency.	

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	No
Document Name	

Comment

IRC Standards Review Committee understands that the current Standards Authorization Request (SAR) doesn't provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SRC recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional reliability benefit but add additional compliance burden to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015.

Since the SDT for this Project recognized that there might be a better placement of the Project Requirements, yet apparently felt that a process to consider addressing Standards other than those in the Project's SAR was not available, NERC should consider a process to allow expediting revised SARs that would enable the SDT to address Standards that were not contemplated in the original SAR, while the Project is ongoing.

The IRC would also like to note that the Standard Efficiency Review Project has made similar observations with respect to consolidation of or better coordination of standards. We would suggest that the SDT work with NERC Staff to follow the approach and principles of the SER team to ensure those efficiencies are realized on this project.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SCE shares the opinion of the MRO NSRF regarding FAC-014-3 R6. Specifically, SCE "agrees with the proposed SOL definition. However, as stated in our (MRO NSRF's) response to question 1, we need additional clarification on the SOL expectation of the SDT." Additionally, SCE believes "it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums." Finally, SCE believes it is good industry practice to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint.

Likes 0	

Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Does planned load shedding include automatic load shedding schemes such as UVLS? Within the operational time frame UVLS should be allowed.	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
See comments in response to question 1.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
See comments in response to question 1.	
Likes 0	
Dislikes 0	
Response	

4. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
Regarding R6: The requirement does not provide sufficient clarity with regard to how SOL methodology is incorporated into RTA and real-time monitoring. For example is the expectation that the methodology be implemented in both RTA and real-time monitoring, or can the real-time monitoring schemes be used to incorporate some aspects of the methodology where the RTA tool lacks capability.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SCE concurs with the MRO NSRF's overall comments regarding FAC-014-3.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that a cleaner approach would be to utilize a definition of SOL exceedance. It is confusing to have FAC-011 and FAC-014 depend on each other to understand what the RC and TOP should be doing with regards to SOL exceedances.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Under part 1.2, Evidence Retention, Requirements R1 through R8 are referenced. However, there are only six Requirements in the proposed revision. ERCOT suggests aligning the Evidence Retention requirement language with the specific number of Requirements. The Violation Severity Levels table provides "the items listed in Requirement 5, Parts 5.1 through 5.6." However, there are only five parts in Requirement R5. ERCOT suggests aligning the Violation Severity Levels table to the specific number of parts in Requirement R5.	
Likes 0	

Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	

Comment
ITC agrees with MRO NSRF that in order to reduce the need for a future Standards Efficiency Review effort, ITC requests the SDT to consider if Requirement R3 is unnecessary and sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it’s essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators. Once the data specification is sent to the Transmission Operators in accordance with IRO-010-2 R2, the Transmission Operators must provide its SOLs to the Reliability Coordinator to meet the obligations of IRO-010-2 R3. This should remove the need for the proposed FAC-014-3 Requirement R3. If kept, there may be overlapping compliance obligations with two requirements for the same activity.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	
Document Name	

Comment
R5 – This should require providing SOL information to Transmission Planners, not just Planning Coordinators, because there is no requirement for Planning Coordinators to provide this information to Transmission Planners. In addition, in FAC-015-1, Transmission Planners are required to coordinate with the SOLs established by the Reliability Coordinators and Transmission Operators. As such, the Transmission Planners should receive SOL information directly from the Reliability Coordinators and Transmission Operators, rather than second hand information from Planning Coordinators. If the SDT decides to proceed with FAC-015-1 as a standard, FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *“Each Planning Coordinator and each Transmission Planner within . . . “*

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower

Answer	
Document Name	

Comment

Requirement R4:

Similar to our comment on Sub-Requirement 4.3 (FAC-011-4) in Question 2, a main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Requirement R4 to establish SOLs that impact on the Interconnection:

"Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirement R5.2.5

A description of the associated system conditions is normally included in the RC's methodology as part of Requirement R4.4 in FAC-011-4. The sub-requirement R5.2.5 can be removed as it is redundant with Requirement R4.4 in FAC-011-4.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO believes that the TPL-001-4 covers SOLs and IROLs in the long-term planning horizon. Therefore MISO agrees that the Planning Coordinator should not be the applicable entity that establishes and communicates SOLs and IROLs. The requirement for the RC to provide the PC the SOL and IROLs should reside in FAC-015-1, not FAC-014.

R5 – Share results of Operations assessments with Planning: Operations uses real time assessment to identify operating limits. This information has value for Operations assessment, however the value of identifying and sharing these limits with the Planning Coordinator is anticipated to have minimal value to planning assessments. This is in part due to the variability of the scenarios studied in Operations, and how closely those will align to scenarios studied in the Planning Horizon.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	

Cowlitz PUD agrees that the establishment of SOLs and IROLs should be consistent for both operational and planning aspects of the BES. Having a single source for SOL Methodology from the Reliability Coordinator, implementation of the SOL Methodology by the Transmission Operator, and requiring the Planning Coordinator and Transmission Planner to coordinate the Planning Assessments with SOLs and IROLs provided by the Reliability Coordinator will improve Reliability. However, Cowlitz PUD cautions that IROLs should be carefully identified such that local isolated limitations remain as SOLs.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	
Comment	

The companies suggest FAC-014 would be strengthened if it better aligned or explicitly addressed the following precepts:

The RC is in the best position to establish guidelines or criteria for determining System voltage limit.

The companies recognize each entities' system is unique in design, complexity, footprint, and Facilities, as is the RC's. To address the differences between systems across the BES, the companies suggest BES reliability will be strengthened by considering the uniqueness of these systems and letting the RC set guidelines or criteria for determining System voltage limits.

The TOP is in the best position to determine limits and avoid conflicts with Facility Ratings.

The revised proposed Glossary Term, while establishing boundaries, may create circumstances that add complexity to determining Facility Ratings, System Voltage Limits, and stability limits. Generally, adding complexity to Standards adds opportunity for undesired results in operating the BES.

To simplify the determination of System Voltage Limits and stability limits, the companies suggest that the TOP determine these values to ensure they do not conflict with Facility Ratings.

Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase II of this project. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
The sub-Requirements of R5.2 are a list of specific criteria with the exception of the newly added 5.2.5. Sub-part 5.2.5 is unnecessary and is too general of a statement and could include a variety of system conditions. It is unclear what the SDT is trying to accomplish with 5.2.5. Further in Requirement R6, OPAs and RTAs are listed as acronyms and have not been previously defined in the standard. This issue should also be addressed.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
R4 in its current form gives the RC the ability to establish stability limits when the limit impacts more than one TOP. PNM proposes the following language for R4: Each Reliability Coordinator, in conjunction with the impacted Transmission Operations, shall establish stability limits to be used in	

operations when the limit impacts more than one Transmission Operators in its Reliability Coordinator Area in accordance with its SOL methodology.

Likes 0	
Dislikes 0	

Response

Kelsi Rigby - APS - Arizona Public Service Co. - 5

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	
Document Name	

Comment

Entergy supports the comments submitted by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	
Document Name	

Comment

For the SDT's consideration

R5.2.2: The language for the requirement & rationale have two different versions. The requirement appears to be missing the language "critical to the derivation of the".

Rationale for R6, inconsistent with R1-R5, leverages an informal interpretation of the R6 standard language.

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

No response.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

See MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	
Document Name	

Comment

In R6 what is the definition of “performance criteria”? NIPSCO believes that “performance criteria” is used in R3 in the establishment of SOLs. It is not something separate from that process. R3 states that the TOP supplies SOLs to the RC according to the RC’s SOL Methodology. R6 implies that "performance criteria" is in addition to what is used to establish SOLs. NIPSCO believes that "performance criteria specified in the Reliability Coordinator's SOL Methodology" should be replaced with "SOLs established as part of R3".

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	
Document Name	

Comment

OKGE supports the comments provided by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	
Document Name	

Comment

MEC supports the MRO NSRF overall comments regarding FAC-014-3.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

Requirement R4:

Similar to our comment on Sub-Requirement 4.3 (FAC-011-4) in Question 2, a main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Requirement R4 to establish SOLs that impact on the Interconnection:

"Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirement R5.2.5

A description of the associated system conditions is normally included in the RC's methodology as part of Requirement R4.4 in FAC-011-4. The sub-requirement R5.2.5 can be removed as it is redundant with Requirement R4.4 in FAC-011-4.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI supports comments provided by NRECA.

Appears that the drafting team meant to include a specific question on the revisions to FAC-014-03 prior asking for comments on the standard that were not already provided. NRECA believes the format of R5 and sub-requirement 5.2 is cumbersome and suggest the following "bolded" modifications for consideration to provide clarity. 5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, shall provide the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1 The value of the stability limit or IROL; 5.2.2 Identification of the Facilities that are included in the derivation to determine the stability limit or IROL; 5.2.3 The associated IROL Tv for any IROL; 5.2.4 The associated Contingency(ies); 5.2.5 A description of the associated system conditions that impacted the determination of the stability limit or IROL; and 5.2.6 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	
Document Name	
Comment	

Appears that the drafting team meant to include a specific question on the revisions to FAC-014-03 prior asking for comments on the standard that were not already provided.

NRECA believes the format of R5 and sub-requirement 5.2 is cumbersome and suggest the following **"bolded"** modifications for consideration to provide clarity.

5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, **shall provide** the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are **included in the derivation** to determine the stability limit or IROL;

5.2.3 The associated IROL Tv for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions that **impacted the determination of the stability limit or IROL;** and

5.2.6 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

To reduce the need for a future Standards Efficiency Review effort, the MRO NSRF requests the SDT to consider if Requirement R3 is unnecessary and sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it's essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators. Once the data specification is sent to the Transmission Operators in accordance with IRO-010-2 R2, the Transmission Operators must provide its SOLs to the Reliability Coordinator to meet the obligations of IRO-010-2 R3. This should remove the need for the proposed FAC-014-3 Requirement R3. If kept, there may be overlapping compliance obligations with two requirements for the same activity.

If the SDT decides to proceed with FAC-015-1; then R1, R2, and R3 obligate each Planning Coordinator and each Transmission Planner to use Facility Ratings that are equally limiting or more limiting than those used by the Reliability Coordinator in its Operations Planning Horizon SOLs. Therefore, FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *"Each Planning Coordinator and each Transmission Planner within . . . "*

R5 – should require providing SOL information to Transmission Planners, not just Planning Coordinators, and not rely on Planning Coordinators to provide them to applicable Transmission Planners, especially since there is not a requirement for Planning Coordinators to do so. However, in FAC-015-1 Transmission Planners are required to coordinate with the Reliability Coordinators and Transmission Operators SOLs. Our preference is for the Transmission Planners to get the SOL information directly from the Reliability Coordinators and Transmission Operators, rather than second hand information from Planning Coordinators.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP believes much of the proposed changes would be beneficial and provide clarity, but would like to provide feedback on some key areas:

While AEP has no objections to the proposed changes to R6, and while acknowledging that no changes were proposed to R2, we still would like to again express our concern how the lack clarity in FAC-011 R6.1.3 potentially impacts these requirements in FAC-014. Once again, clarity is needed in FAC-011 to make it clear these obligations are only in reference to known stability limits and do *not* require TOP-provided, dynamic, real-time stability studies as part of OPAs, RTAs, and Real-time Monitoring. AEP has chosen to vote negative on this revised standard driven by the current lack of clarity in this regard.

The text “in accordance with” is subjective, and could be interpreted inconsistently across RE footprints as well as within RE footprints. For example, would the language from FAC-015-1 “equally limiting or more limiting than” be considered “in accordance with?”

AEP does not object to R1 as proposed, we believe that Transmission Operators should be afforded opportunity to provide input into the process, even if not specifically designated within the standard.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

5. The original posting of FAC-015-1 included six requirements. Industry comments to this original version indicated significant concerns. In response to these concerns, the SDT attempted to streamline and clarify the intended interactions between relevant functional entities and to consolidate the standard into fewer requirements. To achieve this the SDT:

- **Consolidated Requirements R1 – R5 in the original posting into three (R1 – R3) requirements,**
- **Clarified the roles of the Planning Coordinator and Transmission Planner in Requirements R1 – R3, and**
- **Clarified that Facility Ratings are "owner-provided" in Requirement R1.**

The SDT acknowledges that some of the requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc.; however, the Project 2015-09 SAR does not currently authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Do you support the revised FAC-015-1? Please provide any other comments regarding FAC-015-1.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
FAC-015-1 R4 should more specifically state that each Planning Coordinator and Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Operational Planning Analysis or a Transfer Capability assessment in the Operations Horizon to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generation Owner. The current draft wording may be interpreted as requiring the Planning Coordinator and Transmission Planner to coordinate with the Reliability Coordinator for results of 5-year planning assessment, which is not only burdensome to TP/PC but also non-beneficial to the RC where RC focus is on 0-1 year horizon. As an additional comment, any new requirements put on a Near-Term Transmission Planning Horizon assessment or Transfer Capability assessment in the Planning Horizon would more appropriately reside in the respective Standards for those assessments, TPL-001 and MOD-001, not the new FAC-015-1.	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
NPPD supports the comments submitted by the MRO NSRF. In addition, NPPD recommends deleting the sub-bullets under FAC-015-1 R2 and R3. Less limiting performance criteria should not be an option.	
Likes 0	
Dislikes 0	

Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF understands the SDT isn't requesting industry input on the location of the requirements. However, to reduce the need for a future Standards Efficiency Review effort, the MRO NSRF requests the SDT to consider if the proposed FAC-015-1 altogether is needed or if its purpose can be fulfilled with existing standards and/or compliance monitoring processes as described below.

The Data Reporting Requirements in Attachment 1 of MOD-032-1 contains a tabular listing of *"information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon"*. It's also stated in the paragraph above the table *"A Planning Coordinator may specify additional information that includes specific information required for each item in the table below"*. Item 4c in the table is *ratings (normal and emergency)**. The asterisk refers to a note that states *"(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*. It appears these statements along with Requirement R1 of TPL-001-4 establish a compliance expectation for models to *"represent projected System conditions"*, which should include the most limiting Facility Ratings applicable to the modeling scenario. Additionally, if Planning Coordinators, Transmission Planners, Transmission Operators and Reliability Coordinators are not all using the same set of Facility Ratings provided by the Transmission Owner in accordance with FAC-008 R8, then that inaccuracy can be addressed via compliance monitoring for FAC-014, TPL-001 and various IRO/TOP requirements. During its webinar regarding Project 2015-09, the SDT indicated that it would be a very rare occurrence where a Reliability Coordinator would have a more limiting rating than those already provided by Transmission Owners and available to Planning Coordinators and Transmission Planners. Therefore, where is the reliability gap that necessitates creation of Requirement R1 in FAC-015-1?

In a similar manner, if the compliance expectation in Requirements R5 and R6 of TPL-001-4 is for the Transmission Planner and Planning Coordinator to demonstrate a technically sound rationale for voltage and stability criteria applicable to the modeling scenario, then where is the reliability gap that necessitates creation of Requirements R2 and R3 in FAC-015-1?

To ensure relevant entities are considering the information described in FAC-015-1 Requirement R4, it could be added as sub-requirement in FAC-011-4 Requirement R4. To ensure those entities can get the information, it could be requested from the Planning Coordinator and Transmission Planner in accordance with TPL-001-4 Requirement R8. Therefore, is there a need for Requirement R4 in FAC-015-1?

Another consideration in lieu of the new FAC-015-1 standard is to develop compliance guidance, which can improve the industry's understanding of the importance and value in a consistent approach to aligning planning and operational limits.

However, If the SDT decides to proceed with FAC-015, then the MRO NSRF provides the following suggestions for improvement.

Since the FAC-015-1 R1, R2, and R3 obligate each Planning Coordinator and each Transmission Planner to develop SOLs that are equally limiting or more limiting than the Operations Planning Horizon SOLs, then FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *"Each Planning Coordinator and each Transmission Planner within . . . "*

The FAC-015-1 title does not match its stated purpose. We suggest "Coordination of System Planning Criteria and Methodologies with Reliability Coordinator SOL Methodology. The stated purpose of FAC-015-1 is to ensure that Facility Ratings, voltage limits, and stability criteria are coordinated with the Reliability Coordinator's SOL methodology, but R4 is calls for providing selected Planning Assessment and Transfer Capability assessment results to Reliability Coordinators and Transmission Operators. We agree with obligating Planning Coordinators and Transmission Planners to communicate selected assessment results information with Reliability Coordinators and Transmission Operators, but propose that the obligations be added to the respective FAC-013 and TPL-001 standards, not FAC-015-1.

We believe that purpose of FAC-015 would be better fulfilled if it required Planning Coordinators and Transmission Planners to provide their planning horizon Facility Ratings, voltage limits, stability criteria, and methodologies (i.e. TPL-001-4 R5 and R6) to their applicable Reliability Coordinators. This would allow Reliability Coordinators to know what criteria and methodologies Planning Coordinators and Transmission Planners are using in Planning Assessments and better understand how their SOL Methodology might be adjusted to achieve better coordination with the planning horizon criteria and methodologies.

R1, R2, and R3 – We are skeptical that requiring Planning Coordinator and Transmission Planner system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from the Reliability Coordinator SOL methodologies is an appropriate coordination strategy.

R4 – The requirement calls for the communication of CEII information from Planning Assessments and Transfer Capability assessment to impacted Transmission Owners and Generator Owners. This obligation should not be included until it is verified that compliance with the FERC Standards of Conduct can be guaranteed.

Consider the following ideas for sub-parts of a requirement to communicate selected Planning Assessment and Transfer Capability assessment results.

R4.1 – The MRO NSRF agrees with including the type of identified instability but suggest revising the list of examples to match those listed in FAC-011-4 Part 4.1 *". . . (e.g. steady state voltage instability, transient overvoltage or undervoltage instability, unacceptable tie-line phase angle instability, generating unit loss of synchronism, unacceptable generating unit phase angle damping).* Steady state voltage instability criteria can be a percentage of margin from the expected voltage collapse point in a P-V analysis. The term *"voltage collapse"* incorrectly implies that all Planning Coordinators and Transmission Planners choose the voltage collapse point in a P-V analysis as their voltage stability limit. FAC-011-4 changed *"angular stability"* to *"unit stability"*. *"Transient voltage dip criteria violation"* is not a type of instability. If *"transient voltage dip criteria"* is to be retained, then it should be included in R4.2, as an example of an *"associated stability criteria"* for voltage instability. *"Angular instability"* is a very broad type of instability. Consider providing the Planning Coordinator and Transmission Planner with more understanding of what types of specific angular instability by mentioning some specific sub-elements of the category like those suggested above.

R4.2 – Consider adding some stability criteria examples for the benefit of Planning Coordinators and Transmission Planners, such as steady state P-V curve criteria, steady state high and low voltage protective relay trip levels, transient voltage dip criteria, transient overvoltage spike criteria, transient high and low voltage protective relay trip levels, generating unit loss of synchronism criteria, generating unit phase angle damping criteria.

R4.3 – The MRO NSRF requests the SDT consider the following suggestions for clarification:

1.

   - Asociated Contingencies and Facilities are two different items and should be two separate sub-sections.

   - The Contingencies used in Planning Assessments and Transfer Capability assessments include contingencies beyond the Contingencies used in Operational Planning Analysis.

   - *"Facilities critical to . . ."* does not have a clear meaning and uses the 'loaded' wording of *"critical to"*. Consider wording like, *"The Elements that exceed the system performance criteria"*.

   R4.4 – No suggested wording change. However after Planning Coordinators and Transmission Planners describe the studied System conditions, it should explained that the System conditions, which will be used for Operational Planning Analysis, may be considerably different from the studies System conditions (e.g. different known outages, different load forecasts, interchange with economic transfers, different generation resource dispatches), so the reliability impacts identified in the Operations Planning Horizon may be very different from those based on the Near-Term Planning Horizon System conditions.

   R4.5 – The automatic controls and expected system operator actions that are expected to address potential instability, Cascading, or uncontrolled separation in the Operations Planning Horizon should be split into two sub-bullets or be split into two separate sub-sections.

   - A sub-section for automatic control actions could say, "Automatic controls expected to address potential instability, Cascading, or uncontrolled separation available in the Operations Planning Horizon, such as Remedial Action Schemes (RASs), undervoltage load shedding (UVLS), underfrequency load shedding (UFLS).

- A sub-section for system operator actions could say, “Operating Procedures expected to address potential instability, Cascading, or uncontrolled.

R4.6 – We suggest that the wording be modified slightly to something like “Any Corrective Action Plans intended to mitigate or reduce identified instability, Cascading or uncontrolled separation.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	

Comment

LES recommends the following changes to the bulleted list in FAC-015-1 R1.

- Bullet #1: Recommend removing the first bullet since it is not an exception to the RC’s SOL Methodology.
- Bullet #2: Recommend revising the second bullet as follows to be more general and not associated with variations in ambient temperature assumptions only: “Facility Ratings differences are due to variations in **seasonal assumptions such as in** ambient temperature assumptions”.

Additionally, the reference to “Near-Term Transmission Planning Horizon” in R1-R3 should only refer to the Planning Assessment with the Near-Term removed. For example, in R1 the required PC/TP process would likely not specify different Facility Ratings between the Near-Term versus Long-Term planning horizons. Use of the phrase “Near-Term Transmission Planning Horizon” in R4 seems appropriate.

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	No
Document Name	

Comment

NRECA agrees with the consolidation of requirements and the other changes in the proposed FAC-015-1.

As stated in Q4, NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to not only include the TOP and IRO standards, but to also expand the review to include TPL and MOD standards.

Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

AECI supports comments provided by NRECA.

NRECA agrees with the consolidation of requirements and the other changes in the proposed FAC-015-1.

As stated in Q4, NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to not only include the TOP and IRO standards, but to also expand the review to include TPL and MOD standards.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

The use of the undefined term 'instability' in R4.4 could lead to inconsistent results and result in additional compliance burdens that add little to no reliability benefit. As used in FAC-011 R6, instability is not limited to the BES or wide area but instead, as currently worded, applies to ANY instability that has ANY impact to any element or facility. R4.4 should be limited to the interconnection or at the very least the wide-area to prevent misunderstanding.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
See comments under question 6 for additional rationale. BPA would like to see R4 modified to state: R4. Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation *"that adversely impact the reliability of the interconnection or other Reliability Coordinator Area(s)"* identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: [Violation Risk Factor: Medium] [Time Horizon: Longterm Planning]	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports the MRO NSRF recommendation to SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a "micro-managing" manner. That leads to duplication and difficulties regarding interpretation of requirements.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OKGE agrees with the MRO NSRF recommendation to SDT "to consider if the proposed FAC-015-0 altogether is needed or if its purpose can be fulfilled with existing standards and/or compliance monitoring processes".	
Likes 0	

Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not believe FAC-015-1 is necessary and asks the SDT to reconsider whether the standard is needed at all. CenterPoint Energy believes any reliability concern regarding the proper use of SOLs is addressed by existing standards such as FAC-008, FAC-014, MOD-032, and TPL-001. Additionally, the proper communication of SOLS is addressed by existing standards such as IRO-010, IRO-014, and TOP-003.	
Likes 0	
Dislikes 0	

Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports the comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

FAC-015-1 R4.1 should be limited to TPL-001-4 P1-P7 events. Regarding FAC-015-1 R4.5, TPL-001-4 requires that studies are run with RAS, and if no instability is found, then no additional stability studies are run to determine if RAS was needed to maintain the stability. Also, when a RAS is established, the reason for establishing the RAS (i.e., to address instability or thermal problems) is known. FAC-015-1 R4.5 as written would require additional studies in order to determine whether the RAS is needed to maintain stability, and there is no justification for this additional work because the information would not provide any value. Further, TPL-001-4 P1-P7 events do not permit the use of Under Voltage Load Shedding and Under Frequency Load Shedding to address instability, cascading, or uncontrolled separation, which is referenced in FAC-015-1 R4.5. For this reason, AZPS recommends that those actions not be included in FAC-015-1 R4.5.

Each requirement of FAC-015-1 appears to already be included in existing standards, or should be incorporated into existing standards as opposed to creating a new standard. The content of FAC-015-1 R1 should be included in MOD-032. The content of FAC-015-1 R2 and R3 should be included in TPL-001. The Planning Assessment requirements referenced in FAC-015-1 R4 should be incorporated into TPL-001-4, and the Transfer Capability Assessment requirements referenced in FAC-015-1 R4 should be incorporated into FAC-013-3 R5. AZPS urges a change in SAR scope or a new SAR to review all of the affiliated requirements and determine whether there is overlap or potential concern with creating a new standard.

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	

Comment	
PNM believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA without having an impact on reliability. Instead of allowing exceptions, PNM suggest that the RC, TOP, and PA should jointly develop system performance criteria.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy shares the industry recommendation to SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a "micro-managing" manner. That leads to duplication and difficulties regarding interpretation of requirements.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
While we agree with consolidating requirements, we disagree with the approach of the SDT to include requirements R1-R3 in FAC-015. The SDT should consider revising the SAR to include modifications to TPL or MOD standards. The SDT should not go forward with FAC-015 until they have reviewed TPL or MOD alternatives.	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	

Answer	No
Document Name	
Comment	
There are duplicate of work between this standard and MOD which creates a confusion.	
Likes 0	
Dislikes 0	
Response	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
There are duplicate work between this standard and MOD which creates confusion.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment

The SPP Standards Review Group (SSRG) understands that the current Standards Authorization Request (SAR) doesn't provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SSRG recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional reliability benefit but add additional compliance risk to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015.

Additionally, the SSRG recommends coordinated efforts with the Standards Efficiency Review (SER) Team to see if those particular standards can be modified in the Phase II of the SER without having to revise the current SAR. The SSRG understands that Phase II of the SER is dedicated to Requirements that could be combined and/or modified. From our perspective, this coordinated effort will provide value and efficiencies to both projects by identifying and removing redundancy issues.

Finally, the SSRG, while recognizing the IROL is not a part of the current comment period, suggests that during Phase II of the project the drafting team re-evaluate the use of references to Planning Assessments of the Near -Term T instability, Cascading, or uncontrolled separation." The SSRG is concerned that the drafting team may have inadvertently omitted how this reference includes TPL-001-4 Table 1 Extreme Events, as well as Planning Events. The SSRG recommends that the drafting team either clarify that the proposed replacement language for IROLs in associated Reliability Standards, as well as FAC-015-1, is only referring to TPL-001-4 Table 1 Planning Events, or, explicitly direct the planning entities to document those Extreme Events that cause instances of instability, Cascading, or uncontrolled separation if they are not specifically identified in Planning Assessments.

Likes 0	
Dislikes 0	

Response

Spencer Tacke - Modesto Irrigation District - 4

Answer	No
Document Name	

Comment

The planning horizon should be allowed to have more limiting element ratings than the operating horizon, for more reasons than the ones stated in R1.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy is unclear on the expectations listed in the sub-bullets for R1. Can a PC or TP use a less limiting Facility Rating with the justification of one of the sub-bullets, or do all sub-bullets need to be satisfied in order to use a less limiting Facility Rating? The use of the word “or” in the 3rd bullet adds tp the confusion. If the intent is that only one sub-bullet must be satisfied, we suggest the following:

“The process may allow the use of less limiting Facility Ratings due to one of the following:”

Also, the second sub-bullet is not clear on where the ambient temperature assumptions are coming from. Would this be referencing a difference between Planning and Operations?

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1

Answer	No
Document Name	

Comment

There are duplicate of work between this standard and MOD which creates a confusion.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower

Answer	No
Document Name	

Comment

Requirement 1

The intent of Requirement 1 stated in the Rationale for FAC-015-1 “is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System.” Requiring the Planning Coordinator to change ratings to what is provided to the Reliability Coordinator is contrary to established NERC criteria.

The requirement as written would require planning to use different ratings than what is provided for the purposes of planning under MOD-032-1 and FAC-008-3 which is contrary to the stated purpose of the standard. As the Transmission Owners are already obligated to provide planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation).

Requirement 2

The rationale provided for Requirement #2 has strong ties to NERC TPL-001. The intent of this requirement is to try and ensure that Planning is fulfilling its role to determine potential reliability deficiencies of the future planned system and to develop Corrective Action Plans to resolve the reliability concerns. This requirement is viewed as a supplement of TPL-001-4 R5.

The voltage requirements stated in TPL-001-4 R5 essentially state that Planning TPL assessments need to have criteria (and document that criteria) for:

- Acceptable system steady state voltage limits
- Post-contingency voltage deviations
- Transient voltage response

o For this criteria at minimum the criteria need to specific a low voltage level and maximum length of time that the transient voltages may remain below that level.

The idea to implement R2 would be to state our requirements as exactly what is put forward in the RC SOL methodology. In reviewing the criteria for the RC SOL methodology, the above criteria for the TPL standard are all achieved with the exception of post-contingency voltage deviation.

Our recommendation would be that FAC-011-4 R4 list include criteria for post-contingency voltage deviation.

Requirement 3

While the rationale provided for Requirement #3 attempts to have ties to NERC TPL-001, no specific requirement of the TPL standard is identified (like there is in FAC-015-1 R2's rationale).

Requirement 4

The rationale for R4 does not provide justification for the inclusion of Transfer Capability Assessments to be included in this requirement. NERC should clarify as to how referencing to FAC-013 plays a role in the requested communication in FAC-015 R4. Further, if the Transfer Capability Assessment respects known SOLS (R1.2) there would be no reporting in FAC-015 regarding Transfers. Further FAC-015 R4.6 requires discussion of corrective action plans which are not required as part of the Assessment of Transfer Capability.

It seems that their argument for rationalizing this standard is circular to existing standards. For example, the rationale states, "the details required by Requirement R4 will supplement the severe system conditions identified in Requirements R4 Parts 4.4 and 45 of the TPL-001-4". The TPL standard requires that entities evaluate the events that may produce the more severe system impacts. It is unclear about how reporting this information per the FAC-015 standard will improve the TPL assessments. It is also unclear how this information in the near-term planning horizon will benefit the entities to which this information is provided. Instead, when violations are observed in the Planning Horizon, corrective Action Plans should be developed which

resolve the violation.	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Disagree with the RC methodology in FAC-014-3 and therefore by extension disagree with the TP and PC using the proposed RC methodology.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
While we appreciate the constraints the SAR places on the SDT, FMPA cannot support FAC-015-1. FMPA still questions if R1-R3 of the proposed FAC-015-1 is even necessary. From the previous comment period: “We question what the value of R1-R3 is and if the requirements are even needed. R1-R3 are really dealing with TPL-001-4 and there shouldn’t be three additional requirements in FAC-015-1 to deal with the uncommon occurrence of a PC using less limiting Facility Ratings, System steady-state voltage limits, or stability performance criteria. It certainly shouldn’t require a technical justification, it should only require coordination”	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	

The FAC-015-1 title does not match its stated purpose. We suggest “Coordination of System Planning Criteria and Methodologies with Reliability Coordinator SOL Methodology.

The stated purpose of FAC-015-1 is to ensure that Facility Ratings, voltage limits, and stability criteria are coordinated with RC SOL Methodology, but R4 is calls for providing selected Planning Assessment and Transfer Capability assessment results to RCs and TOPs. We agree with obligating PCs and TPs to communicate selected assessment results information with RCs and TOPs, but propose that the obligations be added to the respective FAC-013 and TPL-001 standards, not FAC-015-1.

We believe that purpose of FAC-015 would be better fulfilled if it required PCs and TPs to provide their planning horizon Facility Ratings, voltage limits, stability criteria, and methodologies (i.e. TPL-001-4 R5 and R6) to their applicable RCs. This would allow RCs to know what criteria and methodologies PCs and TPs are using in Planning Assessments and better understand how their SOL Methodology might be adjusted to achieve better coordination with the planning horizon criteria and methodologies.

R1, R2, and R3 – We are skeptical that requiring PC and TP system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from RC SOL Methodologies is an appropriate coordination strategy.

In addition, for R2 and R3, note that edits are needed to these requirements if they will be retained. Specifically, the "stability performance" and "System steady-state voltage" language in each of the sub-bullets of R2 and R3 are reversed (i.e. "stability performance" should appear in R3 and "System stead-state voltage" should appear in R2).

R4 – The requirement calls for the communication of CEII information from Planning Assessments and Transfer Capability assessment to impacted Transmission Owners and Generator Owners. This obligation should not be included until it is verified that compliance with the FERC Standards of Conduct can be guaranteed.

Consider the following ideas for sub-parts of a requirement to communicate selected Planning Assessment and Transfer Capability assessment results.

4.1 We agree with including the type of identified instability but suggest revising the list of examples to match those listed in FAC-011-4 Part 4.1 “. . . (e.g. steady state voltage instability, transient voltage response instability, unit instability, System damping). Steady state voltage instability criteria can be a percentage of margin from the expected voltage collapse point in a P-V analysis. The term “voltage collapse” incorrectly implies that all PCs and TPs choose the voltage collapse point in a P-V analysis as their voltage stability limit. FAC-011-4 changed “angular stability” to “unit stability”. “Transient voltage dip criteria violation” is not a type of instability, but rather a reference to a type of criteria, which should be cited in Part 4.2.

4.2 Consider adding some stability criteria examples for the benefit of PCs and TPS, such as steady state P-V curve criteria, steady state high and low voltage protective relay trip levels, transient voltage dip criteria, transient overvoltage spike criteria, transient high and low voltage protective relay trip levels, generating unit loss of synchronism criteria, generating unit phase angle damping criteria.

4.3 Consider the following suggestions:

- Associated Contingencies and Associated Facilities are two different items and should be split into two separate sub-sections.

- The Contingencies used in Planning Assessments and Transfer Capability assessments include contingencies beyond the Contingencies used in Operational Planning Analysis.

- “Facilities critical to . . .” does not have a clear meaning and uses the ‘loaded’ wording of “critical to”. Consider wording like, “The Elements that exceed the system performance criteria”.

4.4 No suggested wording change. However after PCs and TPs describe the studied System conditions, it should explained that the System conditions, which will be used for Operational Planning Analysis, may be considerably different from the studies System conditions (e.g. different known outages, different load forecasts, interchange with economic transfers, different generation resource dispatches), so the reliability impacts identified in the

Operations Planning Horizon may be very different from those based on the Near-Term Planning Horizon System conditions.

4.5 The automatic controls and expected system operator actions that are expected to address potential instability, Cascading, or uncontrolled separation in the Operations Planning Horizon should be split into two sub-bullets or be split into two separate sub-sections.

- A sub-section for automatic control actions could say, “Automatic controls expected to address potential instability, Cascading, or uncontrolled separation available in the Operations Planning Horizon, such as Remedial Action Schemes (RASs), undervoltage load shedding (UVLS), underfrequency load shedding (UFLS).

- A sub-section for system operator actions could say, “Operating Procedures expected to address potential instability, Cascading, or uncontrolled.

4.6 We suggest that the wording be modified slightly to something like “Any Corrective Action Plans intended to mitigate or reduce identified instability, Cascading or uncontrolled separation.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

We agree that transmission owner-provided Facility (thermal) Ratings should be used in R1 and that the ratings of existing facilities should be coordinated between RC, PC, and TP entities to ensure system model accuracy. Thermal ratings of future facilities planned for the near-term planning horizon would not be coordinated with the RC as these facilities do not exist in the operating horizon.

As proposed, the use of System Voltage Limits described in R2 and stability performance criteria described in R3 would not require coordination between entities, but would be based on the RC methodology and not on local TO planning criteria, which has been filed with FERC and the States. The use of more stringent limits set by the RC would provide the means to unilaterally drive the planning assessment results developed by the PC and TP and could force significant future system expansion above existing planned levels. In our opinion, the language in R2 and R3 needs to be changed to require a more collaborative use of PC and TP existing planning criteria with the RC methodology.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

SRP agrees with the clarification of “owner-provided” Facility Ratings and restructuring of the requirements. However, SRP has concerns with the language found in R1, R2 and R3. In each of these requirements, the Transmission Planner or Planning Coordinator may use less limiting criteria, limits or ratings if they provide technical rationale to affected Transmission Planners, Planning Coordinators or Reliability Coordinators. SRP is concerned because there is no requirement for the affected entities to agree with the technical rationale. In addition, technical rationale is not a NERC defined term so SRP is concerned with what will be considered technical rationale and what will not. What happens if there is a disagreement between the Transmission Planner and the affected entity as to the technical rationale that was used?

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	
Comment	

ITC agrees with MEC and the MRO NSRF recommendations to SDT “to consider if the proposed FAC-015-0 altogether is needed”. The general feeling within numerous industry’s entities is that there is a risk of “over-regulation” as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a “micro-managing” manner. That leads to duplication and difficulties regarding interpretation of requirements.

The Data Reporting Requirements in Attachment 1 of MOD-032-1 contains a tabular listing of *“information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon”*. It’s also stated in the paragraph above the table *“A Planning Coordinator may specify additional information that includes specific information required for each item in the table below”*. Item 4c in the table is *ratings (normal and emergency)**. The asterisk refers to a note that states *“(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*. It appears these statements along with Requirement R1 of TPL-001-4 establish a compliance expectation for models to *“represent projected System conditions”*, which should include the most limiting Facility Ratings applicable to the modeling scenario. Additionally, if Planning Coordinators, Transmission Planners, Transmission Operators and Reliability Coordinators are not all using the same set of Facility Ratings provided by the Transmission Owner in accordance with FAC-008 R8, then that inaccuracy can be addressed via compliance monitoring for FAC-014, TPL-001 and various IRO/TOP requirements. During its webinar regarding Project 2015-09, the SDT indicated that it would be a very rare occurrence where a Reliability Coordinator would have a more limiting rating than those already provided by Transmission Owners and available to Planning Coordinators and Transmission Planners. Therefore, where is the reliability gap that necessitates creation of Requirement R1 in FAC-015-1?

In a similar manner, if the compliance expectation in Requirements R5 and R6 of TPL-001-4 is for the Transmission Planner and Planning Coordinator to demonstrate a technically sound rationale for voltage and stability criteria applicable to the modeling scenario, then where is the reliability gap that necessitates creation of Requirements R2 and R3 in FAC-015-1?

R1, R2, and R3 – We are skeptical that requiring Planning Coordinators and Transmission Planners system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from the Reliability Coordinator SOL methodologies is an appropriate coordination strategy. They also require a documentation burden that may ultimately be eliminated in a later NERC Standards Efficiency Review.

Requirement 4 should not be included in a FAC standard. The TPL standard already provides a provision for anyone with a reliability need to obtain the TPL Assessment. Any of these entities must request the TPL Assessment from the PC or TP and identify the reliability need. They must also demonstrate that they can maintain that the communication of CEII information is not outside the bounds of the FERC Standards of Conduct. R4 provides far too much of an open ended list of information on the transmission system and does not guarantee the required confidentiality.

Finally, ITC, while recognizing the IROL is not a part of the current comment period, suggests that during Phase II of the project the drafting team re-evaluate the use of references to Planning Assessments of the Near Term Transmission Planning Horizon that show results of “instances of instability, Cascading, or uncontrolled separation.” ITC is concerned that the drafting team may have inadvertently omitted how this reference includes TPL-001-4 Table 1 Extreme Events, as well as Planning Events. ITC recommends that the drafting team either clarify that the proposed replacement language for IROLs in associated Reliability Standards, as well as FAC-015-1, is only referring to TPL-001-4 Table 1 Planning Events. If it were to explicitly have the planning entities include and document those Extreme Events that cause instances of instability, Cascading, or uncontrolled separation if they are not specifically identified in Planning Assessments, this list would most likely be extremely long and cause issues for planning entities in their completion of all associated studies.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned with the use of a technical rationale to use less limiting Facility Ratings (R1), less limiting System Voltage Limits (R2), and less limited stability performance criteria (R3). There is nothing that states what should go into the technical rationale, who should determine whether or not the technical rational provides a valid reason for not using the most limiting factor, and what shall occur if the technical rationale is not valid. As written, an entity could put any reason whatsoever for not using the most limiting factor and have no consequence if it is not a valid reason.

Texas RE strongly recommends there be some sort of criteria for a technical rationale, it go through an approval process, and, if not approved, it be sent back to the entity who submitted the technical rationale. At the very least, the technical rationale should explain how reliability is or is not impacted.

Texas RE has the following additional comments regarding Requirement R1:

- PCs and TPs should request facility owners to provide ratings based on the ambient temperature assumptions in the Planning Assessments, and for each ambient temperature assumption in the Planning Assessment, the PCs and TPs should not be able to use a rating which is less limiting than the corresponding owner-provided Facility Rating.

- Higher Facility Ratings for a planned upgrade or addition should only be allowed to be utilized in studies the year the upgrade or addition is expected to be in service and for following years. Facility Rating increases that are only proposed as part of a Corrective Action Plan should not be used in the analysis performed to determine if the System meets performance requirements in Table 1 of TPL-001-4, but may be used to address deficiencies identified as part of the analysis.

Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	

IRC Standards Review Committee understands that the current Standards Authorization Request (SAR) doesn’t provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SRC recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional reliability benefit but add additional compliance burden to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015.

Since the SDT for this Project recognized that there might be a better placement of the Project Requirements, yet apparently felt that a process to consider addressing Standards other than those in the Project’s SAR was not available, NERC should consider a process to allow expediting revised SARs that would enable the SDT to address Standards that were not contemplated in the original SAR, while the Project is ongoing.

The IRC would also like to note that the Standard Efficiency Review Project has made similar observations with respect to consolidation of or better coordination of standards. We would suggest that the SDT work with NERC Staff to follow the approach and principles of the SER team to ensure those efficiencies are realized on this project.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SCE agrees with the MRO NSRF (and MidAmerican) recommendation for the SDT “to consider if the proposed FAC-015-0 altogether is needed”. The general feeling within numerous industry’s entities is that there is a risk of “over-regulation” as several NERC Standards attempt to regulate aspects of the industry in a “micro-managing,” or duplicative manner.	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
FAC-015 creates a sort of double jeopardy for the Transmission Planner by placing the requirement of establishing a process on top of the requirements set out in FAC-001, FAC-007, FAC-011, FAC-014, MOD-032 and MOD-033 to establish and communicate the limits and should not be applicable to entities that already have the requirement to produce and use this data in analysis required by other NERC Reliability Requirements such at TPL-001.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
The purpose of the FAC-015 standard is to ensure the Facility Ratings, steady-state voltage limits, and stability criteria used in the Planning Assessments are coordinated with the RC’s SOL Methodology. **Requirement R4 in FAC-015-1 requires Transmission Planner to communicate its Stability Assessment results to the impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. We agree that Transmission Planner should communicate their Stability Assessment results to impacted entities, but we believe that this requirement belongs to TPL-001 standard and should not be a part of FAC-015 standard.**	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
FAC-015 creates a sort of double jeopardy for the Transmission Planner by placing the requirement of establishing a process on top of the requirements set out in FAC-001, FAC-007, FAC-011, FAC-014, MOD-032 and MOD-033 to establish and communicate the limits and should not be applicable to entities that already have the requirement to produce and use this data in analysis required by other NERC Reliability Requirements such at TPL-001.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SME: The standard is much improved from the previous draft. No comments on the content.	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Correction: in both first and second bullet points of requirement R3, the “steady-state voltage limits” should be corrected as “stability limit”.	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	Yes
Document Name	

Comment

GTC is in agreement with the SDT's proposed FAC-015-1. The coordination of limits between planning and operations is an improvement over the current construct of having separate SOL methodologies for the planning and operations horizons. GTC is in agreement that some requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc. but recognizes the limits of the Project 2015-09 SAR.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

The companies support revised FAC-015-1.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	Yes
Document Name	

Comment

See related comment provided in Question 4.

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
We believe it would be acceptable for the PC to use the RC's SOL methodology or develop their own methodology that does not conflict with the RC's approach. Once this standard is approved in final form, FAC-008 should be checked for interoperability and conformity with FAC-015 such that all ratings are covered(i.e., thermal, voltage, stability).	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Requirement R1 references application to "[e]ach Planning Coordinator and each of its Transmission Planners." However, Measure M1 only refers to the "Planning Coordinator." The same issue exists with respect to Requirements R2 and R3. ERCOT suggests aligning Measures M1, M2, and M3, with Requirements R1, R2, and R3 so that "Transmission Planners" are included in the Measures.	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Measures M1, M2 and M3 must be revised to include the Transmission Planner. Also we support NYISO's comment in regards to R1 and the conditions for using less limiting Facility Ratings. We support the first clause ("The Facility has higher Facility Ratings as a result…"). Allowing for less restrictive Facility Ratings because of differences in temperature seems inappropriate. If a different temperature is used by a planner, they should obtain the Facility Rating for that temperature. As for the possibility of submitting technical	

rationales to other entities, the requirement does not require buy-in by the receiving entities. Since the objective of this requirement is to align planning and operations, we respectfully submit that the Facility Ratings should be consistent in planning and operating models. Where there is disagreement, the more conservative value should be retained. This follows the approach in other standards where, in disagreement, the more conservative option is retained (for example, IRO-014).

The same comment applies to R2 and R3 - that is, we consider that the receiving entity, in particular when it is the RC, should be able to enforce the use of the more conservative assumption. However, for those two requirements we note that a "planned upgrade, addition, or Corrective Action Plans" (like in R1) are not explicitly included as reasons to modify the limits. They should be included like in R1.

We reiterate that the most conservative rating, limit should be used. However, we agree that facility upgrades or additions do not need to be referred to the RC for its confirmation.

The VSL for R4, with its concern with the number of missing characteristics, does not make sense. If a PC or TP were to incorrectly communicate an instability - but only incorrect in one characteristic - this would be a lower VSL, but it could, if that error was important, make the communication useless and put the system at risk. The VSL should be severe, unless the error without consequence from an operational point of view. That is, if the RC was able to take correct actions as a consequence, then the error is without consequence. If the RC's actions were incorrect as a consequence of the error, then it should be Severe.

Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

6. Discussions within the SDT indicated concerns with eliminating some of the components of the approved SOL definition. While the industry feedback was largely supportive of the draft SOL definition provided in the informal posting, the SDT modified the proposed definition to incorporate some of the concepts in the approved version. The SDT believes that the revised definition posted for ballot represents an improvement over the definition provided in the informal posting. Reference the SOL rationale document for more information. Do you agree with the proposed SOL definition?

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
"All" should be "The"	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
"All" should be "The"	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP generally agrees with the proposed definition. However, when read separately from the technical rationale, the phrase "specified System configuration" is ambiguous and does not add clarity to the definition. SRP recommends adjusting the proposed definition to more completely explain the relationship between limits and specified System configurations.	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
While the proposed definition is indeed a vast improvement over the existing, ambiguity is introduced when specifying "facility ratings" if the current definition of IROL (which relies on the definition of SOL) is kept. The singular of facility implies one facility but in practice, IROLs are often established a combination flows not specific to one facility but aggregations of facilities. These IROL MW flow limits may not trigger voltage or stability concerns. The definition should be modified to reflect this concept either by replacing "facility" with "facility(ies)" or by adding a dependent clause such as "facility ratings, either individually or taken in combinations, system voltage…"	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
While the definition is cleaner, the rationale document needs to be clear that exceeding a non-IROL SOL, particularly post contingency, is not a violation of any operating standard or criteria.	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	Proposed definition of SOL.docx
Comment	
As written, it appears that an entity would need to provide multiple Facility Ratings, system voltage limits, and Stability Limits. AZPS recommends amending the proposed definition as shown in the attached WORD document to clarify that multiple limits are not required but may be provided if	

needed.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

NIPSCO believes that the start of the definition should read “SOL is the most limiting of”, as all limits should not be considered a System Operating Limit. We believe only the most limiting of the limits on a facility should be considered a System Operating Limit. If “all” ratings need to be monitored this would present a problem for many software platforms as there is no way to insert more than 3 or 4 ratings into a facility record.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

“Monitoring and assessing” implies the process that is gone through to develop and use an SOL. This definition should focus on what an SOL is, not the process by which SOLs are found or how SOLs are used.

BPA suggested definition:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, to ensure reliable operation of the Bulk Electric System in both the pre - and post- Contingency operating states.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes

Document Name	
Comment	
SCE supports the SDT's revised definition of SOL. The proposed definition improves clarity and eliminates ambiguity that was present in the previous definition. Furthermore, it eliminates several items the definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with MEC and supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	Yes
Document Name	
Comment	
We agree with the proposed SOL definition. A minor comment is to change the singular term SOL to plural SOLs to align with the plural form for limits in the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	

The companies support the revised definition.

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	
Comment	

The proposed definition is an improvement. It removes the redundancy of pre- and post-Contingency operating states.

Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	
Comment	

The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.

Likes 0	
Dislikes 0	
Response	

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	Yes
Document Name	

Comment	
Entergy supports the comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We agree with the proposed SOL definition. A minor comment is to change the singular term SOL to plural SOLs to align with the plural form	

for limits in the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF agrees with the proposed SOL definition. However, as stated in our response to question 1, we need additional clarification on the SOL expectation of the SDT. Is it your intent that each Facility has a thermal-based SOL or can a subset (Flowgates) be used to manage power flow on the system? This needs to be clearly stated in a requirement so that everyone is planning and operating the BES from the same understanding. Additionally, it's not clear if Normal Ratings and normal System Voltage Limits are considered SOLs, if you have higher Emergency Ratings or emergency System Voltage Limits for the Facilities. It could be interpreted to say Normal Ratings and normal System Voltage Limits aren't SOLs if you have higher Emergency Ratings and emergency System Voltage Limits. This understanding translates to compliance expectations in the IRO and TOP Standards for exceedances and when you must implement your Operating Plan. If we're relying on the SOL whitepaper to clarify, then some entities may choose not to follow it saying it's not mandatory. Since the SDT may not be able to answer compliance questions, we request NERC staff to draft a CMEP Practice Guide to inform the industry of the compliance expectations for SOLs as applied in the FAC, IRO and TOP standards.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SME: City Light agrees with the definition.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

On behalf of our City Light SME: There is confusion about why the terms "SOL" and "IROL" need to be removed from some of these standards. In FAC-003, for example, shouldn't any element identified as part of a currently effective IROL be considered under the applicability section, not just things identified in the Planning Assessment?

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

FAC-003-5 should be revised to align with the comments to FAC-015-1 in #5 above. Any requirements associated with a Near-Term Planning Assessment should align with the specific requirements in the approved TPL-001 Standard either the Operations Horizon or to a specific requirement within the TPL-001 Standard – R3.5 and R4.2.

Comments specifically for CIP-014-3: Applicability 4.1.1.3 should simply be removed. The proposed wording change causes confusion with the actual CIP-014 assessment, the whole purpose of which is to identify those Transmission substations that if rendered inoperable or damaged as a result of a physical attach could result in instability, Cascading or uncontrolled separation. The new proposed 4.1.1.3 would either create a circular argument or could inadvertently be interpreted to expand the scopes of TPL-001 and MOD-001. Any revisions to the requirements of the assessments in TPL-001 and MOD-001 should be made in those Standards, not through CIP-014.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No

Document Name	

Comment
While AEP has no objections to the proposed changes to CIP-014, FAC-013, PRC-002, PRC-023 and PRC-026, we do have concerns regarding 4.2.2, Transmission Facilities, within FAC-003. We believe additional text is needed here to ensure no lines are unintentionally excluded by a) the timing of their being identified as part of an IROL and b) the timing of any facilities identified, which could lead to instability, Cascading, or uncontrolled separation within associated planning assessments. AEP recommends that this section be clarified in the following manner… *"Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation* ***<u>or overhead transmission line operated below 200kV that have been established as part of an IROL by the Reliability Coordinator per IRO-014-3 R1.</u>****"* AEP has chosen to vote negative on the proposed revisions to FAC-003, driven by the concerns expressed in this response.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	

Comment
FAC-003-5 should have an implementation period once a study identifies a new Facility below 200 kV (Applicability Section) that could lead to instability, Cascading or uncontrolled separation. An entity needs the time to get that new Facility into it's vegetation plan and meet the clearences. The way the **current FAC-003-4 and proposed Standard FAC-003-5** is written an entity is out of compliance once the new studied Facility is identified if it does not meet clearences and the entity would then need to self report. NPPD recommends an implementation period of up to 24 months to allow for the newly identified facility to be incorporated into it's vegetation plan and for clearences to be met. For the other Standards NPPD supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment	
The MRO NSRF supports the effort of the SDT to eliminate planning-based SOLs and IROLs, but to ensure clarity of expectations the revisions to these standards need to directly map to the applicable TPL-001-4 contingency results that indicate unacceptable instances of instability, Cascading, or uncontrolled separation. As currently proposed, every instance of instability or tripping of multiple elements could be considered in scope for IROLs. Additionally, the SDT should consider that requirements to perform transfer capability studies were determined by the Standards Efficiency Review project to be for commercial purposes and proposed for retirement in the phase 1 SAR. Even though we realize the changes to CIP-002-6 are not in scope for this question and the modifications to the standard were given to the CIP SDT, the 2015-09 SDT is the one who understands the concept of IROLs. Therefore, we would appreciate the SDT passing the following concerns to the CIP SDT. The changes to CIP-002-6 criterion 2.6 and 2.9 do not add clarity. Unfortunately, the proposed changes to criterion 2.9 would bring in most SPS/RAS in the country because these systems are typically designed to avoid instability or a cascading outage scenario. Similarly, the proposed changes to criterion 2.6 substantially expands the scope of analysis. The current CIP-002-5.1 criterion 2.6 language is very clear and narrow because it limits the evaluation to those Facilities that have been shown to impact a large area of the system (i.e. what it means to be an IROL). With the proposed changes, many more Facilities will need to be evaluated for instability, but the end result will still be very few Facilities on the list (and those that make it on the list probably have an SPS/RAS to mitigate the concern). This appears to be an unneeded expansion of the criterion whereas the current language is precise. The SDT should keep in mind that IROLs will still exist under the proposed FAC standard revisions for the operating horizon and, therefore, no change is needed to R2.6 or R2.9. We are not opposed to removing the Planning Coordinator in PRC-002 as an applicable functional entity and having the Reliability Coordinator as the only applicable regional function entity. However, we propose that the Time Horizon of all the Requirements be changed from “Long-term Planning” to “Operations Planning”, to be consistent with the direct and indirect applicability of the Requirements to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We agree with changes to reflect the elimination of Planning-based SOLs and IROLs for CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023.

However, we do not agree with the change to the PRC-026 standard. The Planning Coordinator requires the Reliability Coordinator to provide those SOLS that are based on angular stability in order to assess Criteria 1 and 2 of Requirement R1. We suggest revising Requirement R1 to require the Reliability Coordinator provide the Planning Coordinator with those SOLs that are based on angular stability.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA recommends that CIP-014, FAC-003, FAC-015, PRC-023 and any other standards that reference "instability, uncontrolled separation, or Cascading" with the intent of replacing the term IROL be modified to include the qualifying phrase "*that adversely impact the reliability of either the interconnection or other Reliability Coordinator Area(s)*." This change aligns with the current NERC definitions for IROL and IROL Tv.

NERC definitions:

Interconnection Reliability Operating Limit (IROL): A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages *that adversely impact the reliability of the* Bulk Electric System.

Interconnection Reliability Operating Limit Tv (IROL Tv): The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the *interconnection or other Reliability Coordinator Area(s)* becomes greater than acceptable. Each Interconnection Reliability Operating Limit's Tv shall be less than or equal to 30 minutes.

BPA believes that the two NERC definitions work in conjunction to define when IROLs should be declared. The IROL definition identifies the BES, while the IROL Tv definition identifies an IROL Tv is used to protect the interconnection as a whole or other RC areas.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

Replacement of IROLs with vague unbounded terminology of “instability, uncontrolled separation, and cascading" isn't appropriate and is inferior to the current IROL approach. If IROLs aren't maintained, at a minimum, instability should be quantified with terms such as wide-area or a MW threshold such as the loss of 1,000 MW. The benefit of IROLs is the understanding of an impact threshold clearly understood and outlined in current IROL methodologies.

Vague terminology in zero defect standards results in unnecessary violations, interpretations, and compliance guidance.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No
Document Name	

Comment

OKGE supports the comments provided by MRO NSRF. In addition, The SER Phase 1 project has already proposed that all the requirements in FAC-013-2 be retired. So, we don’t see why this standard needs to be revised any further. We suggest that the SDT coordinate with the NERC SER team to discuss further.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

Until the core standards of this project are settled NIPSCO is not ready to vote on these "dependent" standards and will likely Abstain at this time.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

See MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

CenterPoint Energy supports the elimination of Planning-based SOLs and IROLs; however, CenterPoint Energy does not agree with the changes to the standards listed above. By not incorporating language such as "that adversely impact the reliability of the BES" or some equivalent limiting phrasing into the proposed language used to replace IROL in these standards, the SDT may have expanded the scope of the applicability or requirement. Not all instances of instability rise to the level of adversely impacting the reliability of the BES, and these should not be considered in scope for the standards above.

Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	
Comment	

The proposed responsibility shift in Requirement R5 from Responsible Entity (Planning Coordinator, where presently applicable) to Reliability Coordinator is outside of the scope of Project 2015-09 set forth by the SAR and does not align with the Long-term Planning Time Horizon of PRC-002, as the RC is responsible for real-time operating reliability of its area.

Additionally, Santee Cooper has concerns over shifting the responsibilities of Requirement R5 from the Responsibility Entity (Planning Coordinator) to the Reliability Coordinator at this stage in the existing PRC-002-2 implementation plan.

- The initial implementation deadline for Requirement R5 has past. Capital expenditure decisions have already been made based on the initial identification by the Responsible Entity of BES Elements for which DDR data is required per the prescriptive requirements of the standard.
- Changing the evaluator and spreading the minimum DDR coverage requirement over the Reliability Coordinator's historical simultaneous peak

System Demand vs. the Responsible Entity could potentially change the results of the evaluation, and could potentially require additional equipment from an entity that is unbudgeted at this point.

Furthermore, there is a gap in the Implementation Plan for Project 2015-09 with regard to PRC-002-3.

- In the elements listed that shall remain applicable to the Implementation of PRC-002-3 R2, R3, R4, R6, R7, R8, R9, R10, R11, the Implementation Plan for Project 2015-09 does not address compliance requirements for a re-evaluated list from Requirement R1 or R5. The original PRC-002-2 gives entities three (3) years to be 100 percent compliant with a re-evaluated list from R1 or R5, allowing entities time to budget, design and commission any additional equipment that may be needed to comply. This omission creates a gap in the Implementation Plan, as R1 and R5 include mandatory re-evaluation at least once every five (5) years.

Multiple references to PRC-002-2 within the text of the draft standard have not been redlined, and should be replaced with PRC-002-3.

Multiple references to PRC-023-4 within the text of the draft standard have not been redlined, and should be replaced with PRC-023-5.

Multiple references to PRC-026-1 within the text of the draft standard have not been redlined, and should be replaced with PRC-026-2.

Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	

With the elimination of Planning –based SOLs and IROLs, the Standards drafting team has attempted to come up with alternate means of identification of facilities to fill the void, such as under Applicability Criterion 4.1.1.3 in CIP-014-3. The concern is that the use of terms like “instances of instability,” “Cascading,” and “uncontrolled separation” in place of IROL definition, is very vaguely defined in existing NERC standards and is highly subjective to individual entity’s interpretation and application methodology. Further, there are no thresholds suggested that can be applied to derive these facilities from Near Term Transmission Planning Assessments. Such a list of facilities could vary considerably even between the Planning Coordinator’s Assessment and the Transmission Planner’s Assessment. Use of such vaguely defined criteria will subject entities to undue burden of evaluating lot more facilities under all of the above standards (CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026) with increased risk of additional cost to be incurred. Suggest the standard drafting team come up with more specific methodology in place of IROL or delete this Criterion in CIP-014-3 and other applicable standards.

Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	

Answer	No
Document Name	

Comment

AZPS requests clarification on what contingencies are included in:

- “Facilities that if lost or degraded” in CIP-014 and FAC-003;
- “Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation” in B2 of Attachment B in PRC-023; and
- “Elements associated with angular instability identified in Planning Assessments.”

AZPS suggests the following changes to FAC-013-3:

- Remove R3
- Remove “Reserved for future use” in R1.2 and update numbering accordingly

Additionally, Planning Assessments, completed through TPL-001-4, include multiple categories of contingencies (P0-P7) and Extreme Events as detailed in Table 1 of TPL-001-4. Extreme Events referenced in TPL-001-4 should be excluded from those addressed through CIP-014, FAC-003, FAC-013, PRC-023 and PRC-026. To fail to do so could result in double-counting of contingencies. Further, to fail to do so could result in local impact contingencies being considered as a result of other contingency evaluations. For example, evaluation of Extreme Events under CIP-014 can bring in low impact substations despite the fact that the instability identified would only have a very small impact that is confined to a local area. Such identified local instability does not and should not result in required hardening under CIP-014. For this reason, only Planning Events from Table 1 of TPL-001-4 should be included. AZPS is further concerned that studies that have previously been completed would need to be restudied in accordance with the new standard in order to satisfy the 12 month timeline in the implementation plan even if the timeline prescribed in the existing requirement has a longer timeframe. For example, CIP-014-2 R1 requires studies every 30 calendar months. AZPS does not support doing an additional study for CIP-014-2 R1 before the 30 month deadline that we will have already created a scheduled for in order to be compliant with the new standard before the 12 month implementation date.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

The changes for PRC-002 seems unrelated to the proposed FAC changes.

The proposed changes for CIP-014, PRC-023, and FAC-003 the replacement language is too broad. The Planning Assessment looks at extreme events which have low probability of occurring and for which corrective actions are not required. It doesn’t seem reasonable that extreme events which result in instability, Cascading, or uncontrolled separation are now pulled into scope for CIP-014, PRC-023, and FAC-003 when CAP are not required by the TPL-001.

The proposed change to FAC-013 R1.3 seems unrelated to the proposed FAC change.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy believes there is inconsistency with the language used in the CIP-002-6 Draft of the impact of instability, Cascading, or uncontrolled separation. NV Energy would request that the SDT include "Wide Area Impacts" to the language revisions in CIP-014, FAC-003, and PRC-023:

CIP-014 Applicability 4.1.1.3 should read:

4.1.1.3 *Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near r Only), as Facilities that if lost or degraded are expected to result instances of **Wide Area impacts** such as instability, Cascading, or uncontrolled separation.*

FAC-003-5 Applicability 4.2.2 and 4.3.1.2 should read:

4.2.2. *Each overhead transmission line, operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near ly), as Facilities that if lost or degraded are expected to result in instances of **Wide Area impacts** such as instability, Cascading, or uncontrolled separation.*

4.3.1.2. *Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of **Wide Area impacts** such as instability, Cascading, or uncontrolled separation; or …*

PRC-023-5 Attachment B (Criterion 2) should read:

B2. *The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of **Wide Area impacts** such as instability, Cascading, or uncontrolled separation.*

Likes 0	
Dislikes 0	

Response

Tommy Drea - Dairyland Power Cooperative - 5

Answer	No
Document Name	

Comment

DPC supports the comments of MRO NSRF.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	No
Document Name	

Comment

Comments: An administrative revision to PRC-023-5 is recommended to carry forward the approved implementation timing language from the PRC-023-3 Implementation Plan and the Errata to the Implementation Plan for the Revised Definition of “Remedial Action Scheme” (which included the PRC-023-4 revision). This non-substantive change to bring the current standard under revision into line with the currently approved version (and implementation notes) is necessary to avoid possible future errata revisions. A suggested revision is to include a footnote for the relevant sections in Section 4.2 Circuits (Sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6) as follows:

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. *1*

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.*1*

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. *1*

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. *1*

Footnote 1 suggested language:

1. Circuits identified by the Planning Coordinator in accordance with Requirement R6 shall be compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Likes 0	
Dislikes 0	

Response

Spencer Tacke - Modesto Irrigation District - 4	
Answer	No
Document Name	

Comment	
For CIP-014, FAC-003, PRC-023, and PRC-026, I think there needs to be a revison to every proposed redline change, that states "per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation." To those proposed change statements, I believe we need to add at the end of each one in all the referenced above Standards, the simple phrase ", or other Study." I believe this is needed because the TPL Assessments or Transfer Capability Assessments in themselves, don't necessarily require the type of extreme contingencies to be studied that would cause instability, Cascading, or uncontrolled separation. Hence to demonstrate the impact of these type of extreme contingencies (such as was done for the CIP-014 analysis), studies other than the Annual TPL Assessment or Transfer Capabilty Assessments might need to be completed.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy has concerns with the language proposed as a replacement to the IROL language in these standards. The language, *"per its Planning Assessment of the Near -Term) as Facilities that if lost to only Transmission Planning or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation,"* is too broad as written, and appears to bring TPL-001-4 Extreme Events into scope and other single & multiple contingency events well beyond the scope of the original single contingencies specified in R2 of FAC-010/011 and specified in R5.1.1 of the proposed FAC-011-4 to identify SOL's and IROl's. We believe more limiting language is appropriate. CIP-014- Duke Energy feels that the draft language is too broad (see above). FAC-003- As stated above, we have concerns with the appearance of an expansion of scope. This would be in conflict with the original intent of the standard which did not include such events. We believe more limiting language is appropriate. Also, there appears to be inconsistent use of Planning Coordinator or Transmission Planner (as used in the Applicability section), and Categories 1A-4B which references the Planning Coordinator only. Was it the drafting team's intent that only the Planning Coordinator apply to those Categories? PRC-002- Duke Energy does not support the change from Responsible Entity to Reliability Coordinator in R5. This would be a significant departure from current industry practices since the RC does not currently have assess operation in the Long Term Planning Horizon. This would prompt the need for Reliability Coordinators to revise current processes, and include steps to reach out to entities in its RC Area for this information. We fail to see the reliability benefit of transferring historically planning related activities to the Reliability Coordinator. PRC-023- Duke Energy feels that the draft language is too broad (see above). We believe more limiting language is appropriate. PRC-026- Duke Energy feels that the draft language is too broad (see above). We believe more limiting language is appropriate. Also, there appears to be a grammatical error in R1. Consider removing the "a" before "limiting the output of a generator".	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

FAC-013-3

The companies recommend keeping FAC-013-3 R1.3 without revision and preserve the words "planning practices."

The proposed R1.3 revisions, replacing "planning practices" with the NERC Glossary term, "Planning Assessments," effectively assigns TPL assessment criteria and requirements to FAC-013. Such an outcome is inconsistent with the FAC-013 purpose to "…reliably transfer energy in the Near-Term Transmission Planning Horizon."

Also, by effectively assigning TPL assessment criteria and requirements to FAC-013, assessments are duplicated and establish similar compliance obligations over multiple Standards.

Furthermore, by having similar compliance obligations over multiple Standards creates a compliance conundrum when either Standards yield a similar issue of noncompliance.

CIP-014 FAC-003 PRC-002 PRC-023 and PRC-026

The companies support the proposed revisions.

Likes 0	
Dislikes 0	

Response

Ruth Miller - Exelon - 5

Answer	No
Document Name	

Comment

Exelon GO agrees with commenets filed by Exelon TO

Likes 0	
Dislikes 0	

Response

John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon LSE supports Exelon TO comments.	
Likes 0	
Dislikes 0	
Response	

Becky Webb - Exelon - 6	
Answer	No
Document Name	
Comment	
Exelon MKT suports Exelon TO comments.	
Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
The proposed redline changes in CIP-014 and FAC-003 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. The FAC-013 and PRC-002 changes are acceptable. With regard to PRC-023, the changes made to Criterion B2 have made it very unclear. The language "is selected by" infers that there is some sort of optional or judgement, but there is no indication of what that should be based on. Additionally, referring to Planning Assessment is too vague. Planning Assessments include consideration of extreme events, but these seem inappropriate for consideration in PRC-023. If the decision is made to keep B2 similar to what has been drafted, please change "Planning Assessments" to "assessments", as this would allow for consideration of any available inputs. Proposed language is shown below. Similarly, for PRC-026, R1 criterion 2 is too restrictive by using the term "Planning Assessments". This should be changed to "technical assessment" as shown below. Also in PRC-026, page numbers should be added to the Guidelines and Technical Basis section.	

PRC-023 Criterion B2 further modification in bold below:

*The circuit is selected **identified** by the Planning Coordinator based on assessments **of P0 – P7 Planning Events** that identify instances of instability, Cascading, or uncontrolled separation.*

Additional revision for PRC-026, R1 criterion 2 in bold below:

*Elements associated with angular instability identified in **technical assessments including but not limited to** Planning Assessments.*

Likes 0	
Dislikes 0	

Response

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

MISO agrees with retiring FAC-010.

With regard to PRC-026_R1, the first sub-bullet appears to either have a grammatical error or it should be revised for clarity. “Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or RAS…”. Suggestion is to remove the words “…addressed by a…”.

Likes 0	
Dislikes 0	

Response

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002. The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	No
Document Name	
Comment	
The question is not clear. We do not have the same position in all the standards listed here.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	No
Document Name	
Comment	
It is our understanding that 'Planning Assessment' in the proposed change from referring to IROLs to "…, per its Planning Assessment of the Near [illegible]	

expected to result in instances of instability, Cascading, or uncontrolled separation" refers to studies performed for the Near -Term T Planning Horizon per NERC Reliability Standard TPL-001-4. The term Planning Assessment is in the NERC 'Glossary of Terms Used in NERC Reliability Standards' defined as "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies." To reduce the risk of continued inconsistency, we propose to add "technical analyses such as its" to the text replacing the previous reference to IROLs as well as a minor editorial change to the reference to Transfer Capability assessment in all applicable NERC Reliability Standards listed in Project 2015-09 as well as, if approved, to NERC Reliability Standard CIP-006-2. Hence, we proposed the text replacing the reference to IROLs to read "…, per technical analyses such as its Planning Assessment of the Near -Term Transmission Planning Coordinator's Transfer Capability assessment, as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation."

We agree with changes to reflect the elimination of Planning-based SOLs and IROLs for CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023.

However, we do not agree with the change to the PRC-026 standard. The Planning Coordinator requires the Reliability Coordinator to provide those SOLS that are based on angular stability in order to assess Criteria 1 and 2 of Requirement R1. We suggest revising Requirement R1 to require the Reliability Coordinator provide the Planning Coordinator with those SOLs that are based on angular stability.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	No
Document Name	

Comment

Replacing the term IROL with the IROL definition may lead to inconsistent determinations by different Entities.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA is concerned that the language being proposed to replace defined terms is too broad and creates too many questions regarding how to comply with the standards.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

CIP-014:

The SDT proposed the following language for CIP-014-3 Applicability 4.1.1.3:

Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

ERCOT proposes that “instability” be changed to “system instability.”

ERCOT believes the use of the term “instability” is too broad and could be interpreted to include localized instability events that do not have a widespread impact. This suggestion is consistent with the concern noted in the NERC Methods for Establishing IROLs Task Force (MEITF) report at p. vii:

Specifically, the PRR acknowledged that the use of the word “instability” in the IROL definition is particularly problematic as this term can be interpreted to include any and every instance of instability that spans the entire spectrum of consequences and severity of impact—ranging from one extreme where instability results in the loss of a single small unit to the other extreme where instability results in widespread outage of a major portion of an RC area or beyond. The PRR contended that localized, contained instances of instability that affect a small amount of load have little to no impact on the reliability of the BES and do not warrant IROL establishment.

The MEITF report defines the term “system instability” as:

The inability of the Bulk Power System,* for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a Disturbance.

*Refers to the remaining portion of the interconnected Bulk Power System, with the exception of the Elements disconnected as a result of the Disturbance.

ERCOT agrees that not all instances of instability warrant IROL establishment. For this reason, and to remain consistent with the MEITF report, ERCOT recommends that the proposed language for CIP-014-3 Applicability 4.1.1.3 be modified to include “system instability” rather than “instability.”

ERCOT notes there are other instances in various Requirements where the use of “system instability” may be more appropriate than “instability.”

FAC-003: None

FAC-013: None

FAC-015:

It appears there may be a copy/paste typo. ERCOT suggests using “steady-state voltage,” instead of “stability.”

PRC-002: None

PRC-023: None

PRC-026:

ERCOT is concerned that the phrase, “Elements associated with angular instability identified in Planning Assessments” in R2, Criteria No. 2 creates ambiguity and an unintended expansion in the scope of PRC-026.

ERCOT suggests deleting the current draft Criteria 1 & 2 and replacing them with the following in order to more closely align with the intent of both PRC-026 and Project 2015-09:

1. Generator(s) where an angular stability constraint exists that is addressed by limiting the output of the generator or by a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s). 2. Elements that are monitored in order to enforce an existing angular stability constraint.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP identifies the following adjustments that must be made to avoid confusion to the Reliability Standards: FAC-003-5: (references made to redline version) -Page 10 – Delete the reference to R2 -Page 13 R1 VSL should reference FAC-003-5 Table 2 not FAC-003-4 -Page 24-25 – Delete all references to R2 PRC-026 (references in the Redline) -Entire document: change the references to PRC-026-1 Attachment A & B to PRC-026-1 Attachment A&B PRC-023-5 (references redline document) -Entire Document: Adjust the references to PRC-023-4 to PRC-023-5	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	

Comment

CIP-014-3: Per the CIP-014 Guidance, ITC believes the CIP-014 Applicability 4.1.1.1 to 4.1.1.4 should mirror the CIP-002-5.1a Attachment 1 criterion 2.4-2.7. The proposed changes for CIP-014 Applicability 4.1.1.3 do match the proposed (Project 2016-02 Modifications to CIP Standards) changes for CIP-002-5.1a Attachment 1 criterion 2.6. However, ITC believes any discussion pertaining to CIP-014 Applicability is better suited for “Project 2016-02 Modifications to CIP Standards. In addition, ITC remains concern that the originating changes from FAC Reliability standards diminish the need for a process to ensure the RC/PC/TO entities are including for evaluation facilities and assets to support the intent of the NERC CIP standards. ”

PRC-002-3: Changes made do not affect ITC’s current PRC-002 process.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment

Regarding 4.1.1.3 in the Functional Entities section of CIP-014-3, Southern believes that the verbiage ***“would adversely affect reliability of the Bulk Electric System”*** should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL (see below):

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near Only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ***would adversely affect reliability of the Bulk Electric System***.

Regarding 4.2.2 in the Functional Entities section of FAC-003-5, Southern believes that the verbiage ***“would adversely affect reliability of the Bulk Electric System”*** should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ***would adversely affect reliability of the Bulk Electric System.***

Regarding B2 in the Criteria section of PRC-023-5, Southern believes that the verbiage “***would adversely affect reliability of the Bulk Electric***

System” should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL (see below):

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation that ***would adversely affect reliability of the Bulk Electric System***.

Regarding PRC-002-3, Southern does not believe that the Responsible Entity (under Functional Entities 4.1) should be changed.

Southern Company’s main concern with the proposed changes is not the substitution of the IROL term with the three outcomes – instability, Cascading, or uncontrolled separation – our main concern is the prescriptive nature of naming Planning Coordinator studies which is beyond existing IROL methodologies, and the use of the unbounded term “instability”. For example, compliance with present TPL-001-4 standard for Planning (P) events (and proposed TPL-001-5) requires that any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated as per the Corrective Action Plan. While instability, Cascading, or uncontrolled separation do not have to be mitigated for Extreme Events in TPL-001-4/(future 5), as the name implies, Extreme Events are rare events.

Southern Company, like many other companies, has an IROL methodology that is largely based in RC and PC stability input. This methodology identifies SOLs and any subset of the identified SOLs that should be elevated to IROLs. As such, we suggest that references to specific compliance-based studies such as TPL-001 and FAC-013 be removed and allow the use of in-place proven study methodologies to determine and communicate scenarios that are realistic potential instances of instability, Cascading, or uncontrolled separation. (reference CIP-014, FAC-003, PRC-023 and PRC-026).

Likes 0	
Dislikes 0	

Response

Randy MacDonald - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Looking at FAC-003-5 as an example:

The application of the text "Facility that if lost or degraded are expected to result in instances of instability Cascading, or uncontrolled separation", while used to identify those lines (under 200 kV) that are applicable to FAC-003-5, appears too discretionary. Is the intent to identify those elements that if lost/degraded and in combination with a contingency is expected to result in instances of ....?

Likes 0	
Dislikes 0	

Response

William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
See comments above.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

CIP-014:

- The applicability section 4.1.1.3 in CIP-014-3 specifies that if instances of instability, Cascading or uncontrolled separation occurred due to the loss of a facility in the Near-term planning assessment, it would be applicable to the CIP-014 analysis.
- The term "instances of instability" is not clear and needs to be defined clearly to eliminate confusion of what qualifies a facility to be assessed in CIP-014.

FAC-003:

- Violation Severity Levels (Table 1) (pgs. 13-16)
- Since R2 was removed from the table on pg. 14, there is no documentation of the severity levels for lines above 200 kV that are not "identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation"
- FAC-003 1.4 Additional Compliance Information (pg. 10)
  - There appears to be a typo regarding the footnote that is referenced:
    - "Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the

following:”

- Should this be changed to “footnote 4”? This typo has been in FAC-003-3 & FAC-003-4 versions.
- This change will ensure we are not required to submit tree related outages that are “beyond our control”.

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

See comments above.

Likes 0	
Dislikes 0	

Response

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

The modifications to the standards are not consistent.

We note three key differences:

1. In PRC-002-2, the PC function is removed leaving the RC function, whereas in the other standards (e.g. CIP-014-3), the RC function is removed, leaving the PC function. We disagree with this change.

When PRC-002-2 was being developed, the Drafting Team was aware that different Functional Entities across the continent would be the appropriate parties to be responsible for the Standard’s requirements. This was presented to industry in the Request for Comments posted November 1, 2013 through December 16, 2013. The Responsible Entity was defined in Section 4 of the Introduction in PRC-002-2 accordingly. Nothing in section R5 supposes that the SOL are planning SOL; the PC can obtain the relevant SOL for their determination per requirement R5 of FAC-014-3.

2. In the CIP-013 and FAC-003, the Near Term Transmission Planning Horizon of the Planning Assessment is specified, whereas it is not specified in for the two PRC standards. The two PRC standards should use the same approach. In particular, issues in the long-term horizon of the Planning Assessment should not be relevant to the application of the PRC-023 and PRC-026 standards.

3. In PRC-023, the text “that identify instances of instability, Cascading, or uncontrolled separation” is different than the text “Facilities that if lost or

degraded are expected to result in instances of instability, Cascading, or uncontrolled separation" used in the other standards. The use of different text implies differences that are hard to interpret. We support that the same text should be used in these different standards.

Also, we point out a minor typo in PRC-026-2 :

R1 – (…)

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by [a] limiting the output of a generator (…)

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	Yes
Document Name	

Comment

NRECA agrees with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI supports comments provided by NRECA.

NRECA agrees with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026.

Likes 0	

Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Recommend adding the word "Facility" to the below applicability item from FAC-003-5. With the current wording, radial lines that are 200kV or higher are in-scope of FAC-003-5. This modificaiton allows the radial line exclusion to be utilized, but should not otherwise impact the scope of FAC-003. **4.2.1.** Each overhead transmission line **Facility** operated at 200kV or higher.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst Votes in the Affirmative but provides the following comment for consideration. For PRC-026-2, R1. Criteria 1, ReliabilityFirst comment on the following proposed language: “Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).” The “a” between “by” and “limiting” seems out of place and ReliabilityFirst recommends removal.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	

GTC agrees with the modifications to the standards impacted by the retirement of FAC-010. Further GTC notes the following:

- The removal of the Planning Coordinator as an entity responsible for Requirement 5 in PRC-002 represents a material change to the Applicability section of the standard. GTC agrees with this change and the SDT's rationale that "placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which dynamic Disturbance recording (DDR) data is Required."
- The proposed modification to FAC-013 is an improvement to this standard.
- The streamlined language in the proposal for FAC-003 is a much needed improvement.
- The other modifications represent an appropriate replacement for the planning SOL/IROLs.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

- We believe the proposed language FAC-003, 4.2.2 should be revised for clarity. The proposed R 4.2.2 identifies a line to which the standard is applicable, "Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation."

Based on recent planning assessments and studies related to transfer capability, the PC would not ever add such facilities. If a loss of a single line (whether or not below 200kV) would result in cascading, that would result in the utility failing to comply with TPL-001. Since a PC would have to be compliant with TPL-001-4, the PC would ensure such a sub-200kV line would never be added to the system, resulting in a null set for such lines, rendering 4.2.2 meaningless.

- We also recommend adding the language: "that adversely impact the reliability of the Bulk Electric system" following references to "uncontrolled separation." This addition would bring the language in alignment with the Glossary of terms definition of IROL.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment

Clarifying language should be added to PRC-026 Requirement R1 Criteria 1 to indicate that the Reliability Coordinator will provide the information concerning angular stability constraints to the Planning Coordinator. This would be in alignment with the intent of revised FAC-014 R5.2 and its sub-requirements.

Likes 0	
Dislikes 0	

Response
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	Yes
Document Name	

Comment
We agree with the changes as they are applied consistently throughout the standards. However, if the SDT changes the approach as stated in the previous comments, these areas will need to be revisited. In terms of FAC-003-5 and CIP-014-3, there may be an un-intended consequence of potentially pulling in facilities below 200 kV for compliance with both standards. The language is also not consistent in the FAC-003-5 applicability section, and the Sustained Outage categories beginning on page 10. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment
The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase 2 of this Project 2015-09. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE appreciates the SDT reviewing the standards to identify those impacted by the retirement of FAC-010. Regarding the Implementation Plan, under General Considerations, it states that for PRC-002-3, PRC-023-4, and PRC-005-3, the elements of the prior implementations plans shall remain applicable and are incorporated herein by reference. Texas RE's understanding is that although the effective date of the new proposed versions of these standards is "the first day of the first calendar quarter that is twelve calendar months after the effective date of the applicable governmental authority's order approving the standards", the prior versions of the implementation plans indicated in the general considerations section remains in place. If this is the case, it may be more clear to list out those exact dates that remain in place for the prior versions of the standards. Texas RE also recommends including a question about the implementation plan on each comment form going forward to encourage stakeholders to review the implementation plans.	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	
Document Name	
Comment	
The question is not clear. We do not have the same position in all the standards listed here.	
Likes 0	
Dislikes 0	
Response	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	
Document Name	
Comment	
The question is not clear. We do not have the same position on all the standards listed here.	
Likes 0	
Dislikes 0	
Response	

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC is not opposed to removing the Planning Coordinator in PRC-002 as an applicable functional entity and having the Reliability Coordinator as the only applicable regional functional entity. However, ATC proposes that the Time Horizon for all the Requirements be revised from "Long-term Planning" to "Operations Planning," to be consistent with the direct and indirect applicability of the Requirements to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Document Name	
Comment	
While Hydro One is in general agreement with the proposed retirements and modifications, we recommend the addition of “identified by the Transmission Planner” as follows to the phrase that is to replace occurrences of SOL/IROL: “Facilities identified by the Transmission Planner that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation” This change would clarify that it is the TPs that are expected to identify these facilities for the TOs and TOPs.	
Likes 0	

Dislikes 0	
Response	

Consideration of Comments

Project Name:	2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	8/24/2018
Comment Period End Date:	10/17/2018
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-015-1 AB 2 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 2 OT 2015-09 Establish and Communicate System Operating Limits PRC-002-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 Non-binding Poll IN 1 NB 2015-09 Establish and Communicate System Operating Limits Proposed Definition - System Operating Limit IN 1 DEF

There were 68 sets of responses, including comments from approximately 183 different people from approximately 117 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through FAC-011-4 Requirement R6, similar to the approach within the currently effective FAC standards, rather than through an SOL Exceedance definition. Do you agree with the performance criteria in Requirement R6?

2. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

3. The SDT acknowledges that requirement R6 could alternatively be located within a TOP or IRO standard; however, the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Proposed Requirement R6 was created to correspond with FAC-011-4 Requirement R6 in lieu of creating a definition for SOL Exceedance. Do you agree with Requirement R6?

4. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

5. The original posting of FAC-015-1 included six requirements. Industry comments to this original version indicated significant concerns. In response to these concerns, the SDT attempted to streamline and clarify the intended interactions between relevant functional entities and to consolidate the standard into fewer requirements. To achieve this the SDT:

- Consolidated Requirements R1 – R5 in the original posting into three (R1 – R3) requirements,
- Clarified the roles of the Planning Coordinator and Transmission Planner in Requirements R1 – R3, and
- Clarified that Facility Ratings are "owner-provided" in Requirement R1.

The SDT acknowledges that some of the requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc.; however, the Project 2015-09 SAR does not currently authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Do you support the revised FAC-015-1? Please provide any other comments regarding FAC-015-1.

6. Discussions within the SDT indicated concerns with eliminating some of the components of the approved SOL definition. While the industry feedback was largely supportive of the draft SOL definition provided in the informal posting, the SDT modified the proposed definition to incorporate some of the concepts in the approved version. The SDT believes that the revised definition posted for ballot represents an improvement over the definition provided in the informal posting. Reference the SOL rationale document for more information. Do you agree with the proposed SOL definition?

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Chris Adkins	City of Leesburg	3	FRCC

					Ginny Beigel	City of Vero Beach	3	FRCC
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Chris Wagner	Santee Cooper	1,3,5,6	SERC
					Anthony Noisette	Santee Cooper	1,3,5,6	SERC
					Weijian Cong	Santee Cooper	1,3,5,6	SERC
					Debbie Schneider	Santee Cooper	1,3,5,6	SERC
					Bridget Coffman	Santee Cooper	1,3,5,6	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO

PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC

					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Joseph Smith	Prairie Power	3	SERC
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO

					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC

					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion, Con Ed and NBPower	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC

					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable

Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
					Allan George	Sunflower Elect	1	MRO
					Jim Nail	City of Independence, Power and Light Department	5	MRO
					Robert Gray	Board of Public Utilities (BPU)	3	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					John Rhea	OGE Energy - Oklahoma Gas	5	MRO

						and Electric Co.		
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC

					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Industry response to the draft SOL Exceedance definition indicated numerous significant concerns. Given this response, the SDT concluded that creating a definition of SOL Exceedance which adequately reflects reliable operating principles could create an unnecessary compliance burden if action is not taken to substantially modify the existing TOP and IRO standards. Therefore, the SDT maintained system performance criteria through FAC-011-4 Requirement R6, similar to the approach within the currently effective FAC standards, rather than through an SOL Exceedance definition. Do you agree with the performance criteria in Requirement R6?

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Requirement R6.3 does not address SOL violations, but only checks against instability, cascading, or uncontrolled separation, even though this criteria is being used to evaluate performance on additional single or multiple contingency events (R5.2) for use in OPA and Real-time assessments. This suggests that SOL violations would be allowed for these contingencies.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments. Requirement R6.2.3 is applicable to stability SOL exceedances, not R6.3. Requirement R6.3 uses portions of the definition for IROL such that those contingencies which should be monitored / studied to prevent IROLs have a set criteria against which they should be measured.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

The language presented in the R6 is unclear and can lead to different interpretations. The language in R6 needs further clarification.

The drafting team needs to clarify that both actual pre-Contingency state and anticipated pre-Contingency state referred in R6.1 are referring to a TPL equivalent of P0 (system normal) state of the transmission system.

The drafting team should consider rephrasing the language in R6.2.1. Drafting team proposing not to allow usage of Emergency Ratings for contingency events irrespective of presence of operating plan is in complete variation of the planning standard requirements that allows usage of emergency ratings for contingencies described in R5.1.1.

The real time pre-Contingency state could be much different than the anticipated pre-Contingency state and the operating plan proposed for the anticipated pre-Contingency state may not be adequate during the real time pre-Contingency state. Under these conditions, not allowing the operators to use the Emergency ratings is very much disadvantageous and opposite to the intent of PRC-023 where the operator should be allowed to have flexibility to operate the system under Contingency conditions.

PacifiCorp recommends rephrasing 6.2.1 requirement as below

“Flow through Facilities are within applicable Emergency Ratings. Flow through a Facility must not be above the Facility’s highest available Rating, following an N-1 contingency.”

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. The drafting team did not include references to the P0 state in standard TPL-001-4 due to the fact that in operations, the system is commonly not in an "all facilities in-service state" and, hence, not necessarily in the defined P0 state defined in Table 1 of TPL-001-4. Instead, the SDT sought on language general language that would work for pre and post-contingent states. The SDT has revised the language to refer to the pre-contingent state as one with "no Contingencies" and the post-contingent state by evaluating performance for single Contingencies defined in FAC-011-4.

The SDT made some language revisions in requirement R6.2.1, resulting in the following remaining language:

> "Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating."

The SDT left the first sentence so that time constraints in any thermal limits had to be respected (for example, a 4 hour rating could not be used for more than 4 hours), and retained the sentence you noted with regard to the highest rating use. We believe these edits largely capture your concern.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF supports the efforts of the SDT to clarify for the industry what is considered SOL exceedance in the context of the IRO and TOP Standards. We appreciate the SDT listening to the concerns raised by industry regarding the previously proposed SOL Exceedance definition and we agree with the SDT's approach to abandon that potential change. We also agree with the SDT's concept that the Reliability Coordinator's SOL Methodology must address the system performance criteria to ensure consistent identification of SOLs. However, what is still not broadly understood is if each Facility must have an associated thermal-based SOL dependent on current system topology. In Requirement R3 it addresses establishment of a voltage-based SOL at each bus, but there isn't a similar requirement for thermal ratings. Is it the expectation of the SDT that each Facility has a thermal-based SOL or can a subset (Flowgates?) be used to manage power flow on the system? This needs to be clearly stated in a requirement so that everyone is planning and operating the BES from the same understanding.

Additionally, it's not clear if exceeding the Normal Rating or normal System Voltage Limit is considered a SOL exceedance if you have a higher Emergency Rating or emergency System Voltage Limit for a specified time duration. It could be interpreted to say there isn't SOL exceedance until you're over the highest value of the Emergency Rating. This understanding translates to compliance expectations in the IRO and TOP Standards for when you must implement your Operating Plan. If we're relying on the SOL whitepaper to clarify, then some entities may choose not to follow it saying it's not mandatory and we'll continue to have disagreement and confusion in the industry.

In order to support this project, the MRO NSRF needs to understand all the compliance expectations for SOL exceedances, including those associated with the IRO/TOP standards. Is every indication where the FAC-011 R6 performance criteria is exceeded considered a violation of FAC-014 R6 and/or an inadequate real time Operating Plan? Are current operating protocols, which are agreed upon by the Transmission Operator and Reliability Coordinator and allow for temporary exceedances while control actions (such as LMP binding) are being implemented, now going to be prohibited and considered violations? As the proposed performance criteria (for post-contingent thermal and voltage exceedances) does not include any time threshold (in analogy with Tv for IROLs) does that imply the Transmission Operator and Reliability Coordinator would NOT be given any timeframe (such as 30 minutes) to correct an exceedance (particularly post-contingent thermal or voltage exceedances), before it becomes a reportable event and a potential compliance issue? Will the performance criteria be identical independently of the system state (i.e. if the system is in N-1 as opposed to N-4, or even more severe, topology conditions)? Is the Transmission Operator expected to perform a timing analysis to determine if ramp rates, start-up times and location and amount of load shedding are adequate every time it operates above the Normal Rating but below Emergency Rating to verify its Operating Plan will eliminate exceedance within the timeframe of the Emergency Rating? Would the proposed performance criteria not allow for any regional differences even in cases where a Reliability Coordinator is not registered as a Transmission Operator, but has critically important mitigating control actions under its responsibilities? We do not want to unintentionally approve a standard that creates overly burdensome compliance demonstration expectations for the industry, while the SER project is actively seeking ways to streamline and reduce these burdens. Since the SDT cannot answer all these questions, then we request NERC staff to draft a CMEP Practice Guide to inform the industry of the compliance expectations for SOLs as applied in the FAC, IRO and TOP standards.

Will entities be forced to create separation between the highest Emergency, Emergency, and Normal ratings if they are currently the same? An example is a conductor limited transmission line with a 10-minute time constant where all three ratings are identical. Does an entity have to de-rate the line by increments of sag temperature or percentage to create time between ratings or be in violation of the FAC-011-4 timing requirements. Short time frames of under 30 minutes could also lead to a violation of FAC-011-4 R6.5. Short time frames under 30 minutes aren't sufficient time for a system operator to consider "all" other available system adjustments before implementing load shedding.[A1]

To further explain, we believe the proposed performance criteria in FAC-011-4 Requirement R6 seems to capture the essence of SOL exceedance. However, we are concerned the proposed language creates a significant reliability/compliance burden for Transmission Operators and Reliability Coordinators as follows:

1. R6.2 - The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception. When coupled with R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA. This is an infeasible expectation for the Transmission Operator and Reliability Coordinator to include in their RTAs and OPAs, since R5.1.1 contains no caveats to limit the list of applicable single contingencies.
2. R6.2.1 - The flows on a transmission element may exceed the applied Emergency Rating during the dynamic time period, but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the *"applicable Emergency Rating"* for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis. It may be that the SDT does not intend to pull in dynamics in 6.2.2 but it is a logical reading of the standard.
3. R6.2.3 - As noted above, although this is the desired result, it is infeasible to perform dynamic analyses of all R5.1.1 contingencies as part of either an RTA or an OPA. In fact, it is an extremely expensive proposition to perform any real time dynamic simulations due to the complexities of maintaining an accurate dynamic model that incorporates traditional transmission equipment let alone the myriad of user written or proprietary dynamic models in use today for FACTs devices and variable generation.
4. R6.3 and R6.4 contain the same problems as noted above. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the Reliability Coordinator to provide a very limited list of contingencies. Still, even with a limited list, the language of R6 and its sub-parts does not limit the scope of what a Transmission Operator would be required to run under FAC-014-3 (see R2 of that standard). Rather, FAC-011-4 R6 language implies that a Transmission Operator would be required to evaluate all of the contingencies identified by a Reliability Coordinator, not just those that apply to the Transmission Operator's footprint. Note that FAC-014-3 R2 limits the Transmission Operator to identifying SOLs to its footprint, but it does not limit the contingencies a Transmission Operator would need to consider.
5. R6.5 - The standard incorrectly eliminates planned load shedding from consideration when a RAS or UVLS programs may have specifically established the need to take such action to maintain system stability for the particular contingencies under consideration.

We offer the following proposed improvements to address the comments above:

- R6.1.1, R6.1.2, R6.2.1 and R6.2.2 could be improved by clarifying that these sub-requirements are only describing steady-state conditions. Each requirement could have the following leading statement added: *"Under steady-state analysis:"*.
- In addition, R6.2.1 and R6.2.2 would also benefit from adding the word *"Anticipated"* ahead of the terms *"Flow"* and *"Voltages"* in these requirements, respectively, to make it clear that these are potential system flows and voltages, not real time flows and voltages, being evaluated.

Regarding the scope of dynamic simulations, the best location to make modifications is likely the R5 and R5.1 language, not R6. Proposed modifications are as follows:

- R5 - Strike *"and performing the Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study"* since this language is redundant to the R6 performance criteria language that will require these contingencies to be evaluated as part of the RTA and OPA. With this removed, R5 is tailored to only describe what contingency events need to be examined for the identification of SOLs.

R5.1 - Remove the language regarding *"determining stability limits and performing OPAs and RTAs"* and add *"for use in determining steady state SOLs",* since the SOL methodology should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to R5.3.

- R5.2 - Remove *"for use in performing Operational Planning Analysis and Real-time Assessments"* since, again, this is adequately covered by R6, and add in language as follows *"for use in determining steady state SOLs"*.

R5.3 - Strike the word *"additional"* from the existing R5.3 language and add the following to the end of the requirement: *"where the identified single Contingency events involving the loss of a generator, transmission circuit, transformer, shunt device, or single pole block in a monopolar or bipolar high voltage direct current system must simulate either: (a) Normal Clearing of a single phase to ground or three phase Fault (whichever is more severe) or (b) tripping without a Fault condition"*.

- Regarding the Transmission Operator performing a certain set of contingencies, the R6.2, R6.3 and R6.4 language could all be modified to state: *"The evaluation of applicable potential single Contingencies …"* (for R6.2) and *"The evaluation of the applicable potential Contingencies …"* (for R6.3 and R6.4).

R6.5 could be improved by clarifying that RAS and UVLS actions should be implemented in the stability analysis, as applicable. The SDT should also recognize that underfrequency load shedding (UFLS) may be a necessary part of system stabilization once a RAS operates if that RAS is creating a planned islanded system. As such, UFLS may also be a warranted load shedding component when performing stability analysis. R6.5 language could be modified by adding *"planned load shedding, other than Remedial Action Scheme (RAS) or UVLS action, is acceptable ..."* and then adding a new sentence that reads, *"The use of UFLS programs should only be simulated when incorporated as part of the system design to maintain stability (e.g., RAS)."*

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. Those comments, and those of other Midwestern entities such MISO and MidAmerican Energy Co., have provided focus to the SDT's efforts since the second posting.

Those efforts have resulted in revisions to FAC-011-4, FAC-014-3, TOP-001 and IRO-008 which we believe address the concerns you raise above, and other commenters have noted. These revisions have been made to accomplish the following:

- Have SOL exceedances determined in the appropriate TOP and IRO standards rather than the FAC standards.
- The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. In addition, numerous wording changes have been implemented within requirement R6 in response to comments such as those you have above.
- FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.
- The measures for a few TOP and IRO standards were revised to better describe a more complete set of potential evidence that may be sued to show compliance. In addition, the standard rationales have been revised to explain how this evidence may be used to show compliance with the standards.

We believe these changes, which were developed with the support of and feedback with staff from your company and others from within MISO, should address these commonly held industry concerns.

To summarize, the SDT's standard revisions have sought to provide a common minimum framework for industry to determine SOL exceedances, where appropriate in the TOP and IRO standards, and have added process to help improve the required communications on SOL exceedances. The SDT has done this while expanding the list of evidence to minimize any resulting compliance documentation burden. We look forward to your review of our efforts with our new posting and appreciate any comments you may offer.

In addition to these general comments, let us address some of the specific questions you pose.

The SDT worded requirement R2 such that the RC provides a method for the TOP to determine which facility-owner ratings to use. If the facility owner provides ratings for all of their assets, we would expect they are modeled. To expand upon the example you offered, if the RC's SOL methodology states that the RC needs a 10 minute, 1 hour and 24 hour thermal rating. For this example, let's assume the facility-owner only offers a 24 hour, or normal rating. The RC's methodology should describe how to use rating sets which do not perfectly match what the RC seeks. In this instance, it is likely the normal rating would be used for the 24 hour, 1 hour and 10 minute ratings. The RC would not require that the facility owner provides other ratings, but the facility owner would clearly see what ratings the RC seeks to use with its TOPs. This would not preclude the use of flowgates, but we believe does set the expectation that ratings provided would be used to operate. Likewise, this requirement does not require facility owners to provide amongst the ratings they offer.

Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture that "planned manual load shedding", if included in an Operating Plan, should be a measure of last resort. With respect to RAS, requirement R4.6 requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations". However, R4.7 requires "that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits". The use of UVLS and UFLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	No
Document Name	
Comment	

NRECA agrees that it is not necessary to create a definition of SOL Exceedance, but still believes the new FAC-011-04 R6 requirement creates undue compliance burden by prescribing an excessive number of sub-requirements. The structure of R6 is confusing. Many of the sub-requirements that are not standalone with references to other requirements in the proposed standard.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comment. The SDT has taken comments from numerous entities and attempted to improve the language and decrease some of the complexity. However, the SDT does not understand how the number of sub requirements in and of itself creates undue compliance burden. The sub requirements in R6 were derived from the existing FAC-011-3 sub requirements in R2, which are performance requirements which help determine SOL exceedances. The specificity included in FAC-011-4 R6 was to remove ambiguity that exists in the current standard. The references to other requirements in R6 only exist to note which sets of contingencies (defined by a specific requirement) ae applicable to which sets of performance requirements. Managing SOLs is a job each RC / TOP must do, and the SDT agrees R6 provides clarity in determining SOL exceedances.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comments provided by NRECA.

NRECA agrees that it is not necessary to create a definition of SOL Exceedance, but still believes the new FAC-011-04 R6 requirement creates undue compliance burden by prescribing an excessive number of sub-requirements. The structure of R6 is confusing. Many of the sub- requirements that are not standalone with references to other requirements in the proposed standard.

Likes 0	

Dislikes 0	
Response	
The SDT appreciates your comment. The SDT has taken comments from numerous entities and attempted to improve the language and decrease some of the complexity. However, the SDT does not understand how the number of sub requirements in and of itself creates undue compliance burden. The sub requirements in R6 were derived from the existing FAC-011-3 sub requirements in R2, which are performance requirements which help determine SOL exceedances. The specificity included in FAC-011-4 R6 was to remove ambiguity that exists in the current standard. The references to other requirements in R6 only exist to note which sets of contingencies (defined by a specific requirement) ae applicable to which sets of performance requirements. Managing SOLs is a job each RC / TOP must do, and the SDT agrees R6 provides clarity in determining SOL exceedances.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The use of the undefined term 'instability' could lead to inconsistent results and result in additional compliance burdens that add little to no reliability benefit. As used in FAC-011 R6, instability is not limited to the BES or wide area but instead, as currently worded, applies to ANY instability that has ANY impact to any element or facility. R6.1.3 and 6.2.3 should be limited to the interconnection or at the very least the wide-area to prevent misunderstanding.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments offered. The quoted term (instability) and language was taken from the definition of IROL in the NERC glossary of terms. The SDT will consider including in R6 impact on the BES to limit the potential scope of instability, per your comment.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No

Document Name	
Comment	

MidAmerican Energy Company (MEC) understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance.

MidAmerican supports the SDT's proposal to create a definition of SOL exceedance, **as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities**. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations

We certainly appreciate the SDT's rational approach of not proceeding with the proposed definition of SOL exceedance having in mind significant number of negative comments which were received in October, 2017, primarily from MISO and SPP Regions.

Unfortunately, instead of patient continuation of efforts to adjust and improve proposed definition of SOL exceedance, the NERC Standard Drafting Team decided to take, in our view, **inappropriate approach of incorporating that controversial and arguable (although somewhat modified) definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard. We consider this pathway as potentially worse and more risky in comparison with coming up with definition of SOL Exceedance. The reason for such a characterization is that by substituting definition of SOL Exceedance via embedding it as a performance criteria into FAC-011-4, the SDT would expose a number of TOPs and RCs to risk of directly violating FAC-011-4 (Requirement 6) and associated penalties, if (non-agreed upon in terms of definition) exceedances of system operating limits occur either in RTA or OPA**.

Furthermore, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with an approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance **and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better** than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

Fundamental principles and complexities of real power systems do not allow for ignoring the time dimension that always exist when implementing corrective control actions when temporary exceedances of SOL occur, especially in RTA. That was, unfortunately, overlooked in proposed versions of FAC-011-4 and FAC-014-3.

The role of SOL exceedance definition (or performance criteria within FAC-0114-R6), in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate that infrastructure**.

Our quite specific reasons for NOT agreeing with the proposed Requirement 6 of FAC-011-4 are:

1. **Requirements 6.1.1; 6.1.2 and 6.2.1** use the phrase *"when System adjustments to return the flow/voltage within its Normal Rating/Voltage Limits could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits"*.

We would like to show our appreciation to the SDT for their reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance. In this particular case we are pleased that the SDT now considers exceedance of Emergency (rather than Normal) limits as a reportable event.

However, there is a problem with using the phrase "*could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits*" *as* clearly pointed out by Mr. Terry Volkmann. We completely agree with his comment: "*This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate.... TOP (in MISO and SPP reliability footprints) cannot perform such analyses, because the RC/market operator has all the data and tools to do the analysis....* ***This analysis is best served as an internal control not a compliance obligation.*** " MEC agrees with Mr. Volkmann that above mentioned quoted phrase shall be eliminated from the draft of the standard.

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6

The second problem is that it is necessary to differentiate between flow exceedances and voltage exceedances in terms of risk to the equipment and the time tolerance.

We recommend the following definition:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***

- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***

- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***

- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1.
    i.
        a. *Steady state Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings*.
        b. *Steady state Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits*.

1. **Requirements 6.1.3 and 6.2.3** refer to preventing instability, cascading or uncontrolled separation.

- We find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.1.3 and 6.2.3 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

We recommend the following definition:

- ***Any established stability limit (non-IROL) or limit that may cause cascading outages or uncontrolled separation shall not be exceeded for longer than the 30 minutes, or defined by Operating Plan.***

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1\.

i.

a. *Any established stability limit (non-IROL) is mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology and Operating Plan, or with RC's approved post-contingency action plan.*

b. *System-wide Instability, Cascading or uncontrolled separation do not occur.*

2\.

i.

a. *Any established stability limit (non-IROL) is mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology and Operating Plan, or with RC's approved post-contingency action plan.*

b. *System-wide Instability, Cascading or uncontrolled separation do not occur.*

1. **Requirement 6.2.1** is of particular importance and probably the single, most frequent concern in present industry's practice. MidAmerican Energy Company appreciates SDT's reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance/performance criteria. However, we would like to draw the SDT's attention to the following issues with their present formulation of the Requirement 6.2.1, which states that:

"*provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings*. ***Flow through a Facility must not be above the Facility's highest Emergency Rating*.**"

We would like to point out several issues with regard to this formulation:

- First, **the proposed definition does not recognize time-frame associated with exceedances of the Facility's highest Emergency Rating**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). Others exceedances may last several minutes (5-30 minutes, just for sake of example) due to time constraints associated with operators' response to these exceedances and physical reality/timing of corrective control actions that need to be implemented. More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.2.1 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

- Second, regarding the phrase "*Flow through a Facility must not be above the Facility's highest Emergency Rating*", the SDT's formulation appears to be based on the Project 2014-03 Whitepaper. We need to draw attention of the SDT that the original version of the NERC White Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability impact so that it has localized impact**". Subsequent version of the NERC White Paper (revision of January

2015) introduced statement that "Post-contingency flow in this range is not acceptable". **This revision, with a major impact, was never presented to the industry, never approved by the Industry and, in our opinion, was step in the wrong direction. The most recently published revision adds clarity and improved formulations, but still departs from the original concept and ignores time dimension that is necessary to implement corrective control actions, especially for inevitable short term exceedances in RTA, on a contingency basis.**

- Third, the SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "performance criteria/SOL exceedance" may easily cause an incorrect expectation that TOP/RC's control actions response to these two types of exceedances should be similar, in terms of timing, logging and recording.

- Fourth, **it is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability**.

- Fifth, there is a problem with using the phrase "*could be executed and completed within the specified time duration of those Emergency Ratings" as* clearly pointed out by Mr. Terry Volkmann. We completely agree with his comment: "*This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate…. TOP (in MISO and SPP reliability footprints) cannot perform such analyses, because the RC/market operator has all the data and tools to do the analysis….* ***This analysis is best served as an internal control not a compliance obligation***." MEC agrees with Mr. Volkmann that this phrase shall be eliminated from the draft of the standard.

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified

time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis)? It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6.

• Sixth, regarding the **language in FAC-011-4 (R6.2.1)** *"Flow through a Facility must not be above the Facility's highest Emergency Rating"*, let's consider the following scenario. TOP operates in REAL-TIME with one scheduled outage (N-1 topology). Then a fault occurs (single event such as bus fault or similar) and takes out of service two (or more) facilities, thus bringing the system in real-time into N-3 topology condition. Now, RTCA starts showing overloading for next single contingency (N-4).

The concern is if the language in the draft of the standard assumes that **the performance criteria are identical, independently of the system state** (i.e. if the system is in N-1 as opposed to N-3, or even more severe, topology conditions). We certainly understand that in OPA such a scheduled outage would not be approved if it causes SOL exceedances. However, what will be applicable performance criteria if that event happens in real-time due to single event? Of course TOP will implement its Operating Plan to correct the exceedance, but due to significantly deteriorated topology (for which the system was never designed) it may take longer time period to eliminate exceedance on a contingency basis. Or, analysis may show that only firm load shedding may eliminate the exceedance.

The issue is that if the same performance criteria are applicable independently of topology conditions, in order to avoid performance criteria violation (on a contingency basis) the only viable option might be pre-contingent firm load shedding to correct contingency based (not real-time) exceedance.

We recommend the following definition for 6.2.1:

- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

Alternatively, our comments can be formulated in the following red-line (highlighted in yellow changes):

1.

   i. *The evaluation of potential single Contingencies listed in Part 5.1.1 for system intact and N-1 operating conditions, against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:*

      a. *Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings. Post-Contingency flow in this range that is not mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology, or without RC's approved post-contingency action plan, constitutes reportable exceedance to RC. The Operating Plan developed and mutually agreed to by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding, while normal congestion relief control actions are being implemented, to ensure potential impact is localized. Flow through a Facility must not be above the Facility's highest Emergency Rating.*

      b. *Voltages are within emergency System Voltage Limits. Post-Contingency voltage outside of the emergency System Voltage Limits that is not mitigated within the time-frame specified in (and in accordance with) the RC's SOL methodology, or without RC's approved post-contingency action plan, constitutes reportable exceedance to RC. The Operating Plan developed and mutually agreed to by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding, while normal control actions for eliminating System voltage exceedance are being implemented, to ensure potential impact is localized..*

Rationale for using Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating***. It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

- **In contrast to this, we believe that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage**.

- Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

- We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this manner and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

- The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that issuing a new Short Term Emergency rating would be an alternative for the TOP to pursue rather than agreeing with its RC on a post-contingency action plan. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment** (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data and technical facilities justifications**. Consequently, as opposed to being "pushed/forced" to using technically unjustified short-term emergency/load shedding ratings, each TOP and RC might need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

1. **Requirements 6.3 and 6.4**:

Our comments can be formulated in the following red-line (highlighted in yellow changes):

1.

    i. *The evaluation of the potential Contingencies identified in Part 5.2 (which are not mitigated within the time-frame specified in, and in accordance with, the RC's SOL methodology) against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.*

The evaluation of the potential Contingencies identified in Part 5.3, (which are not mitigated within the time-frame specified in, and in accordance with, the RC's SOL methodology) demonstrates that instability does not occur.

Likes 0	

Dislikes 0	
Response	

The SDT appreciates the comments of MidAmerican Energy Co. and, more so, its participation in the SDT team's efforts since the second posting. Comments such as yours have provided focus to the SDT's efforts since the second posting.

Those efforts have resulted in revisions to FAC-011-4, FAC-014-3, TOP-001 and IRO-008 which we believe address the concerns you raise above, and other commenters have noted. These revisions have been made to accomplish the following:

- Have SOL exceedances determined in the appropriate TOP and IRO standards rather than the FAC standards.
- The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. In addition, numerous wording changes have been implemented within requirement R6 in response to comments such as those you have above.
- FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.
- The measures for a few TOP and IRO standards were revised to better describe a more complete set of potential evidence that may be sued to show compliance. In addition, the standard rationales have been revised to explain how this evidence may be used to show compliance with the standards.

We believe these changes, which were developed with the support of and feedback with staff from your company and others from within MISO, should address these commonly held industry concerns.

To summarize, the SDT's standard revisions have sought to provide a common minimum framework for industry to determine SOL exceedances, where appropriate in the TOP and IRO standards, and have added process to help improve the required communications on SOL exceedances. The SDT has done this while expanding the list of evidence to minimize any resulting compliance documentation burden. We look forward to your review of our efforts with our new posting and appreciate any comments you may offer.

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No

Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Requirement 6.2.2 should be modified to mirror 6.2.1: **6.2.2.** Voltages are within applicable emergency System Voltage Limits, provided that System adjustments could be executed and completed within the specified time duration of those emergency System Voltage Limits.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment. Your comment was considered and edits to R6.2.2 were made based upon it.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	

Comment	
ReliabilityFirst votes in the negative for the following two reasons. 1. For requirement R6 part 6.5, ReliabilityFirst believes not being permitted to plan to drop load prior to taking all other actions seems is not technically correct. Here are a few real life scenarios that ReliabilityFirst is aware of: there are Remedial Action Schemes that drop non-firm load for first contingency events. There is another Remedial Action Scheme that drops 1/3 of the total station load for a breaker failure event. RF recommends the following changes to Part 6.5 for consideration: "In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding [non-firm load] is acceptable [and planned shedding of firm load is acceptable] only after all other available System adjustments have been made [or where pre-approved by state regulators, and the shedding of load with Remedial Action Schemes.] 2. For Requirement R6 parts 6.1.1, 6.1.2, and 6.2.1, these three statement assume that the ONLY way that flows, voltages can be controlled within a specified time duration is with system adjustments. There are times when it is known that voltages or flows will change without the operator making any system adjustments. The operator could know that the 2nd shift at a factory ends in 5 minutes, and that there is no 3rd shift. RF recommends the following changes to Part 6.1.1, 6.1.2 and 6.2.1 for consideration: 6.1.1 - Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used [when flows can be returned to within Normal Ratings within the specified time duration of those Emergency Ratings.] 6.1.2 - Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used [when voltage can be returned to within its normal System Voltage Limits within the specified time duration of those emergency System Voltage Limits.] 6.2.1 - Flow through Facilities are within applicable Emergency Ratings, [provided that flows can be returned to within Normal Ratings System within the specified time duration of those Emergency Ratings]. Flow through a Facility must not be above the Facility's highest Emergency Rating.	
Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	

Response	
The SDT appreciates your comments. With respect to your first observation, the SDT believes sub requirement 6.5 in R6 allows automatic load shedding as part of a RAS and does not treat that as manual load shedding. This will be described in the rationale supporting the requirement. Therefore, the examples you note would be acceptable per to proposed language. With respect to your second observation, changes were made to the subject sub requirements removing system adjustments or adding "other System changes", with both changes being responsive to your comment.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
R6 uses the term "performance criteria". This is the same term used in R6 in FAC-014-3 (see NIPSCO comments for question 4). Using the same term in two different standards with different context is confusing. For FAC-011-4 R6 NIPSCO suggests eliminating the phrase "Bulk Electric System performance criteria" and just placing a ":" after the word "following".	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your offered comments. The SDT has eliminated the reference to performance criteria in FAC-014-2. In addition, the SDT has revised R6 and the use of performance criteria within the proposed standard. The SDT is retaining the term due to proposed FAC-011-4 R6 mapping to FAC-011-3 R2, which is the requirement in the existing standard which defines the expected level of system performance when SOLs are respected.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NERC Standards Review Forum comments.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy)" does not agree with the performance criteria in FAC-011-4 Requirement R6 and believes that the language is ambiguous and unnecessary. In particular, the use of the term "instability" in Requirements R6.1.3 and R6.2.3 without any qualifiers may broaden the scope of the language, which could lead to inconsistent results. CenterPoint Energy recommends that the SDT revise the language in Requirements R6.1.3 and R6.2.3 to clarify that instability that adversely impacts the reliability of the BES is what is intended.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments offered. The quoted term (instability) and language was taken from the definition of IROL in the NERC glossary of terms. The SDT did include in its R6 impact on the "BES"to limit the potential scope of instability, per your comment. The SDT also made many other revisions to R6 to improve its clarity.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No

Document Name	
Comment	
Entergy supports comments submitted by MidAmerican Energy Company.	
Likes 0	
Dislikes 0	
Response	
Please see response to MidAmerican Energy Company.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not have an issue with the performance criteria set forth in FAC-011-4 R6. However, the use of performance criteria could still result in ambiguity regarding what qualifies as a “SOL Exceedance.” For this reason, AZPS recommends that the SDT reconsider use of a defined term for “SOL Exceedance.” Additionally, if there is intent to continue to use the term “SOL exceedance” within the body of reliability standards, then both industry and the ERO Enterprise would benefit from the clarity that would result from a definition of the term.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment offered. While the SDT supports your perspective in the value of an explicit SOL exceedance definition, it was apparent from prior postings and comments that the industry as a whole did not. Our latest FAC-011-4 revision, with the proposed R6, is our attempt at providing a minimum set of performance criteria across the industry for establishing SOL exceedances. R6 should be the minimal basis any RC uses to define SOL exceedances within its footprint. We hope you can understand our rationale and support the proposed FAC-011-4 language in our next posting.	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports the SDT's proposal to create a definition of SOL exceedance, **as long as that definition would NOT cause unintended consequences in terms of setting unrealistic expectations or imposing additional and undesirable administrative compliance burden on numerous entities**. In this effort, the SDT should carefully assess repercussions on reliability and efficient market operations

NV Energy believe the SDT took an **inappropriate approach of incorporating that controversial and arguable (although somewhat modified) definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard. We consider this pathway as potentially worse and more risky in comparison with coming up with definition of SOL Exceedance. The reason for such a characterization is that by substituting definition of SOL Exceedance via embedding it as a performance criteria into FAC-011-4, the SDT would expose a number of TOPs and RCs to risk of directly violating FAC-011-4 (Requirement 6) and associated penalties, if (non-agreed upon in terms of definition) exceedances of system operating limits occur either in RTA or OPA**.

Furthermore, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with an approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance **and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better** than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

Fundamental principles and complexities of real power systems do not allow for ignoring the time dimension that always exist when implementing corrective control actions when temporary exceedances of SOL occur, especially in RTA. That was, unfortunately, overlooked in proposed versions of FAC-011-4 and FAC-014-3.

The role of SOL exceedance definition (or performance criteria within FAC-0114-R6), in our opinion, should be to clearly and unambiguously formulate critical operational borderlines of reliable operations, while **respecting existing limitations of existing transmission infrastructure and human resources that operate that infrastructure**.

We appreciate that the SDT listened to the industry's comments and gradually improved the definition of SOL exceedance. In particular, we are pleased that the SDT now considers exceedance of Emergency (rather than Normal) limits as a reportable event.

However, there is a problem with using the phrase *"could be executed and completed within the specified time duration of those Emergency Ratings/Voltage Limits"*. We agree with previous commenting of: *"This implies that in order to use the range between normal and emergency rating for an anticipated contingency, a timing analysis needs to be performed before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate.... **This analysis seems to be better served as an internal control not a compliance obligation**.'*

The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6

The second problem is that it is necessary to differentiate between flow exceedances and voltage exceedances in terms of risk to the equipment and the time tolerance.

We share the industry recommendation of the following definition:

- ***Actual steady state flow on a BES Facility is greater than the Facility's highest Emergency Rating for any time period.***
- ***Actual steady state flow on a BES Facility is above the Normal Rating but below the next Emergency Rating for longer than the time frame of the next Emergency Rating.***
- ***Actual steady state voltage on a BES Facility is greater than the emergency high voltage limit for time frame identified by the TOP.***
- ***Actual steady state voltage on a BES Facility is less than the defined emergency low voltage limit for time frame identified by the TOP.***

1. **Requirements 6.1.3 and 6.2.3** refer to preventing instability, cascading or uncontrolled separation.

- We find it inappropriate that **the proposed definition does not recognize time-frame associated with exceedances of established stability limits**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.1.3 and 6.2.3 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

We recommend the industry discussed following definition:

- ***Any established stability limit (non-IROL) or limit that may cause cascading outages or uncontrolled separation shall not be exceeded for longer than the 30 minutes, or defined by Operating Plan.***
-

1. **Requirement 6.2.1** is of particular importance and probably the single, most frequent concern in present industry's practice. MidAmerican Energy Company appreciates SDT's reasonable approach of listening to the industry's comments and gradually improving the definition of SOL exceedance/performance criteria. However, we would like to draw the SDT's attention to the following issues with their present formulation of the Requirement 6.2.1, which states that:

"*provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings*. ***Flow through a Facility must not be above the Facility's highest Emergency Rating*.**"

We would like to point out several issues with regard to this formulation:

- First, **the proposed definition does not recognize time-frame associated with exceedances of the Facility's highest Emergency Rating**. If not recognized, this can lead to hundreds of meaningless (nuisance) exceedances (for sake of an example, such as those that last less than 1 minute and have magnitude of less than 1%). Others exceedances may last several minutes(5-30 minutes, just for sake of example) due to time constraints associated with operators' response to these exceedances and physical reality/timing of corrective control actions that need to be implemented. More importantly, it should be noticed that even present definition of the IROL violation has associated Tv time threshold (or 30 minutes) before it becomes a compliance issue. Proposed formulation of 6.2.1 should include the time threshold (in analogy with Tv) so that RCs/TOPs would be given specified time frame to correct exceedance, before it becomes compliance issue.

- Second, regarding the phrase "*Flow through a Facility must not be above the Facility's highest Emergency Rating*", the SDT's formulation appears to be based on the Project 2014-03 Whitepaper. We need to draw attention of the SDT that the original version of the NERC White Paper (from May 2014) was stating that "Post-contingency flow in this range is not acceptable **unless Operating Plan address reliability impact so that it has localized impact**". Subsequent version of the NERC White Paper (revision of January 2015) introduced statement that "Post-contingency flow in this range is not acceptable" . **This revision, with a major impact, was never presented to the industry, never approved by the Industry and, in our opinion, was step in the wrong direction. The most recently published revision adds clarity and improved formulations, but still departs from the original concept and ignores time dimension that is necessary to implement corrective control actions, especially for inevitable short term exceedances in RTA, on a contingency basis.**

- Third, the SDT's proposed definition of the post-Contingency flow SOL exceedance **fails to recognize the important difference between actual, pre-contingency SOL exceedance and calculated, post-contingency RISK of SOL exceedance**. This attempt to include both of them under the single, generic term "performance criteria/SOL exceedance" may easily cause an incorrect expectation that TOP/RC's control actions response to these two types of exceedances should be similar, in terms of timing, logging and recording.

Fourth, **it is perfectly clear and understandable that both of these types of exceedances require and should trigger implementation of a control action from Operating Plan, but they should be treated *differently in terms of urgency and severity of mitigating control actions*, as they have different repercussions on system reliability**.

- **The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between**

Normal and Emergency Rating (either in real-time or on a contingency basis)? It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources. If such timing analysis cannot be performed (or is not performed due to lack of time or other reasons, or simply not logged/recorded) that may trigger non-compliance, concerning FAC-011 R6 in conjunction with FAC-014 R6.

• Fifth, regarding the **language in FAC-011-4 (R6.2.1)** *“Flow through a Facility must not be above the Facility’s highest Emergency Rating”*, let’s consider the following scenario. TOP operates in REAL-TIME with one scheduled outage (N-1 topology). Then a fault occurs (single event such as bus fault or similar) and takes out of service two (or more) facilities, thus bringing the system in real-time into N-3 topology condition. Now, RTCA starts showing overloading for next single contingency (N-4).

The concern is if the language in the draft of the standard assumes that **the performance criteria are identical, independently of the system state** (i.e. if the system is in N-1 as opposed to N-3, or even more severe, topology conditions). We certainly understand that in OPA such a scheduled outage would not be approved if it causes SOL exceedances. However, what will be applicable performance criteria if that event happens in real-time due to single event? Of course TOP will implement its Operating Plan to correct the exceedance, but due to significantly deteriorated topology (for which the system was never designed) it may take longer time period to eliminate exceedance on a contingency basis. Or, analysis may show that only firm load shedding may eliminate the exceedance.

The issue is that if the same performance criteria are applicable independently of topology conditions, in order to avoid performance criteria violation (on a contingency basis) the only viable option might be pre-contingent firm load shedding to correct contingency based (not real-time) exceedance

We recommend the following industry discussed definition for 6.2.1:

- ***Projected post-Contingent loading on a BES Facility is greater than the highest Emergency Rating for longer than 30 minutes with NO agreed upon Post Contingency Action Plan that would mitigate the condition if the Contingency were to occur.***

We believe there is need for using a Post-contingency action plan concept

- The main difference between our proposed definition and the SDT's proposed definition is the **concept of post-contingent action plan**. *The Post-contingency action plan is the RC's/TOP's agreed upon control action to be used* ***while the normal congestion management processes are attempting to return the projected post contingent flow within longer-term rating****.* It is very important to note that the Post-contingency action plans are **NOT** a vehicle to justify continual operation where the projected post contingent flow is above Facility's highest Emergency Rating.

In contrast to this, we believe that the Post-contingency action plan developed by TOP and RC is required to address potential impacts and post-contingent mitigating strategies, including but not limited to load shedding or generator tripping, while normal congestion management actions are being implemented, to ensure potential impact is localized and to prevent equipment damage.

- Therefore, we would NOT consider SOL exceedance to exist anytime the Projected post-contingency flow is above Facility's highest Emergency Rating, but only for those situations when the Projected post-contingency flow is above the Facility's highest Emergency Rating (Rate C) for longer than 30 minutes **WITHOUT associated post-contingency action plan**.

- We recognize that there may be situations in the system when normal congestion management is not effective or has been exhausted, and the projected post-contingent loading on a facility remains greater than the highest available emergency rating. In this situation, load shedding may be the sole remaining option to address the projected post-contingency loading. The TOP and RC may decide to operate in this manner and not implement load-shedding pre-contingency if the impacts would be localized. In this case the SOL exceedance would be reportable, even though a post-contingent action plan exists, since normal congestion management is no longer taking place.

- The SDT's concept insists on the concept "highest Emergency Rating". Our definition is based on the concept of "post-contingency action plan". We do recognize that issuing a new Short Term Emergency rating would be an alternative for the TOP to pursue rather than agreeing with its RC on a post-contingency action plan. **The huge practical obstacle to issuing higher emergency rating (or "Load Shed Rating**") that the Industry always faced is that each TOP would have to **get manufacturers' confirmations for using shorter term Emergency Ratings (such as 10-minute ratings) for every single piece of equipment** (breakers, switches, wave traps, CTs conductors, all pieces on transformers etc). Majority of manufacturers would not be even able nor willing to provide such a data. Therefore, **for practical reasons, it is almost impossible to get such a short-term ratings based on manufacturers' data and technical facilities justifications**. Consequently, as opposed to being "pushed/forced" to using technically unjustified short-term emergency/load shedding ratings, each TOP and RC might need to define criteria within their Operating Plan for using post-contingent action plans. These criteria might be based, for sake of example, on Relay Loadability Limits of transmission facilities.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments you offered. The SDT has made changes to Requirement R6 that it believes provides additional clarity. The SDT believes this is an important and critical part of creating consistency as to what constitutes an SOL exceedance which provides uniformity for the industry and a commensurate improvement to reliability. These changes are consistent with the SOL Whitepaper. The SDT has attempted to address some concerns of unnecessary compliance burden to include addition verbiage in proposed TOP-001-6 M14 as well as providing FAC-011-4 R7 and corresponding inclusion of the SOL methodology into TOP-001-6 R15.

The SDT has tried to provide clarity in performance requirements captured in R6 such that it is clear that not meeting performance requirements constitutes an SOL exceedance, which then triggers other requirements to mitigate and communicate such exceedances as identified in the IRO and TOP standards (e.g. implementation of Operating Plan). SOL exceedance does not equate to a violation of the requirements and there is no required timeframe to mitigate an SOL exceedance other than the subset identified to be IROLs. However, an entity is required to implement its Operating Plan as identified in TOP-001 R14. So not meeting performance requirements (i.e. SOL exceedance) does not constitute a violation, but rather a violation would occur only if the responsible entity did not fulfill the obligations of the requirements that surround how to respond to SOL exceedances for example.

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	No
Document Name	
Comment	

We believe the SOL exceedance definition did create an unnecessary compliance burden. However, the approach the SDT took does not reduce the compliance burden by moving the SOL Exceedance definition to a requirement. Requirement R6 is overly complicated and confusing. It has 11 sub-parts and references other requirements four separate times. Compliance standards should be clear and should be able to stand alone without the need to cross reference other requirements.

Likes 0	

Dislikes 0	
Response	
The SDT appreciates the comments you offered. The SDT has made changes to Requirement R6 that it believes provides additional clarity. The SDT believes this is an important and critical part of creating consistency as to what constitutes an SOL exceedance which provides uniformity for the industry and a commensurate improvement to reliability. The SDT has attempted to address some concerns of unnecessary compliance burden to include addition verbiage in proposed TOP-001-6 M14 as well as providing FAC-011-4 R7 and corresponding inclusion of the SOL methodology into TOP-001-6 R15.	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group (SSRG) believes that the performance criteria as described in R6 should be simplified and imbedded where appropriate in the other requirements of FAC-011-4. For example, performance criteria pertaining to steady state voltage should be included in R3.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments. The SDT has revised the language in R6 to simplify it based on comments. However, the SDT believes separating the performance criteria into the other requirements would make the revised standards more confusing. The proposed FAC-011-4 R6 maps to the existing FAC-011-3 R2, which is a separate set of requirements that establishes performance expectations when meeting SOLs per the RC's SOL methodology. The SDT believes maintaining R6 separately minimizes the complexity of a complex topic.	
Spencer Tacke - Modesto Irrigation District - 4	
Answer	No
Document Name	
Comment	
For Pre-Contingency conditions, emergency limits should not be allowed to be used.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment. The SDT initially wrote the sub requirements in R6 just as your comment noted, but subsequent discussion showed that unexpected real time condition changes, such as variations in load level or transfers, can result in System changes which may push thermal or voltage performance beyond normal limits. This led the SDT to include the use of emergency limits potentially for pre-contingency conditions for non-contingent events and maintain consistency with the SOL white paper.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	No
Document Name	
Comment	
Duke Energy requests further clarification on the use of "pre-Contingency state" in R6.2. Was it the drafting team's intent that an RC should anticipate a "pre-Contingency state"? Was this a typographical error? Should "post-Contingency state" be used instead? Duke Energy is unclear on the expectations for R6.4. Is it the drafting team intent that with the use of the term "demonstrates" in R6.4, that entities are required to do stability studies in Real-time? The drafted language appears to be more suitable for Planning Coordinators and Transmission Planners, not for Operators of the BES in Real-time. We suggest the drafting team consider the following language for R6.4: *"The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that the system will be operated within stability limits."* Should other Time Horizons be considered for R6 as well, (Same Day)?	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments. The SDT has removed the pre-contingency state reference in 6.2 and hopefully provided more clear and concise language in the proposed requirement. With respect to your second question, the SDT does not expect operating entities to perform real time stability analyses. Based on this and other comments, previously proposed R6.4 has been removed. The SDT considered Same Day, but thought it best to include the furthest out Time Horizon (Operations Planning), recognizing that SOL exceedances, due to the inclusion of Real Time Assessments, would be Same Day and Real Time also.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No

Document Name	
Comment	

General Observation

The companies believe reliability and establishing compliance thresholds are better served by keeping performance criteria within the performance Standards, e.g. TOP and IRO Standards, and keeping Standards that establish a methodology free from such performance criteria.

Like the SDT's statement in Question 3, the companies agree that to address the issue, revisions would likely need to be made within a TOP or IRO standard and the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards.

Suggestion: Add Flexibility

The companies recognize each Registered Entities' system is unique in design, complexity, footprint, and Facilities. To address the differences between systems across the BES, the companies suggest FAC-011-4 R6 language provide flexibility to accomplish the reliability outcomes offered in the proposed revisions by leveraging entities' FAC-008 Facility Rating Methodology and applicable internal documents to guide:

- When Normal and Emergency Ratings/Voltage limits are used under pre or post-contingent conditions, and
- The allowable time duration for the applicable condition.

Suggestion: Remove Prescriptive Language

Also, the companies suggest removing prescriptive language to provide entities more flexibility executing Requirement 6. Replacing the NERC Glossary Terms, "Normal Ratings" and "Emergency Ratings" with the words "applicable ratings" or "applicable voltage limits" will provide the suggested flexibility without compromising BES reliability.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates your comments. The SDT explored revisions to the TOP and IRO standards to better incorporate the performance requirements and their implications with SOL exceedances. After much effort and dialogue within the SDT and with other industry representatives, the SDT is revising R6 to allow the RC, within its methodology, to define what constitutes an SOL exceedance, using as a starting basis the performance criteria listed in a revised version of R6.

With that said, and while recognizing the stated interpretation of the standards, the SDT did not see the TOP and IRO standards with any obvious location to define System performance criteria. In addition, while the TOP and IROL standards use "SOL exceedance" numerous times, there is no definition of the term anywhere within the standards. Recognizing this and past comments on the SDT's prior postings on FAC-011, the SDT is revising FAC-011-4 R6 to allow each RC to define SOL exceedances in their methodology, using as an initial basis the performance criteria in R6. This tact should allow each RC the flexibility needed to account for any unique concerns within its footprint while allowing a more seamless use of SOL exceedances defined by this methodology in the TOP and IRO standards.

With regard to your comments on ratings, the FACT SDT has, over its three years of existence, discussed the ratings provided by FAC-008 numerous times, and believes that the ratings supplied by the facility owners via FAC-008 should be those used by the TOPs and RCs. Furthermore, proposed R2 and R3.2 in FAC-011-4 note that owner facility ratings should be respected for thermal and voltage, respectively.

The SDT discussed at length whether Normal / Emergency limits versus "applicable" limits were the better terms to be used in the proposed standards. The consensus was that "applicable" ratings was too general a term, and Normal and Emergency limits could accommodate any ratings / limits provided by the facility owners. The language in R3 already allows numerous methods by which a TOP can devise a set of voltage limits for all, or some, of the set of facilities within its footprint for the purpose of determining SOLs, which should be responsive to your comment on using "applicable voltage limits".

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	

Although the current FAC standards include performance criteria, MISO believes that they should reside in IRO and TOP standards. The FAC standard should focus on defining acceptable Operating Limit methodologies. With respect to the proposed performance criteria, MISO has the following concerns:

- Revised standard and SOL exceedance definition appears to imply that exceeding the System Operating Limit (SOL) is not allowed. This makes SOLs more restrictive in management than IROLs, for which there is an allowance to exceed the rating as long as the load is reduced to below the rating prior to exceeding the Tv of the facility. There is no Tv allowance for SOLs, as the definition is currently written.

In particular, the performance criteria as written fail to allow time for the RC or TOP to respond to an event, and readjust the system without immediately putting them in violation of the performance criteria. For example, RTA will show all elements within their emergency ratings per the criteria, but then a contingency occurs and the next RTA shows one or more elements above the highest emergency rating.

- Transmission system could be underutilized, if the SOL Exceedance definition is implemented as currently written.
- Planning standards recognize exceedances of operating limits will occur, and require a plan to mitigate those exceedances. This definition does not allow for the same to occur in Operations

- R6.5 appears to disallow load shedding that may have been specifically designed as part of a RAS or UFLS scheme.

Finally, any change to SOL exceedance in the IRO and TOP standards need to be clear that exceeding a non-IROL SOL, particularly post contingency, is not a violation of any operating standard or criteria.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. The SDT appreciates the comments you have provided. The SDT has made several edits to Requirements R4, R5, and R6 and their subparts that the SDT believes addresses many of the comments. The SDT has tried to provide clarity in performance requirements captured in R6 such that it is clear that not meeting performance requirements constitutes an SOL exceedance which then triggers other requirements to mitigate and communicate such exceedances as identified in the IRO and TOP standards. So not meeting performance requirements does not constitute a violation, but rather a violation would occur only if the responsible entity did not fulfill the obligations of the requirements that surround how to respond to SOL exceedances for example.

Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture that "planned manual load shedding", if included in an Operating Plan, should be a measure of last resort. With respect to RAS, requirement R4.6 requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations". However, R4.7 requires "that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits". The use of UVLS and UFLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.

Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Do not agree with 6.5, too restrictive. Should be allowed to apply non-consequential load loss.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment.	

Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture that "planned manual load shedding", if included in an Operating Plan, should be a measure of last resort. With respect to RAS, requirement R4.6 requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations".

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	No
Document Name	
Comment	

The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception.

R6.2.1 - The flows on transmission element may exceed the applied Emergency Rating during the dynamic time period but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the "applicable Emergency Rating" for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis

R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

R6.3 and R6.4 contain the same problems. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the RC to provide a very limited list of contingencies.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

R6.5 - The standard incorrectly eliminates planned load shedding from consideration when RAS or UVLS programs may have specifically established to take such action to maintain system stability for the particular contingencies under consideration.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. The SDT believes steady state contingency analysis of the System should include all contingencies defined in R5.1.1 of FAC-011-4. However, the SDT has revised R4.2 such that only those contingencies expected to produce the most severe stability results need to be examined. This prevents having to test the entire contingency list for stability, as you commented for sub requirement 6.2.3.

The SDT included the phrase "steady state" to allow transient flow / voltage conditions to not be applicable to these sub requirements.

R6.3 has been rewritten and previously proposed R6.4 removed. IT was never the intent that either R6.3 or R6.4 require real time stability analysis. The SDT was silent on the question in R6 to allow entities to continue their present practices, whether it was using off-line analyses to establish defined stability limits which are monitored in terms of pre-contingent conditions in real time or performing real-time stability analysis. This will be documented in the rationale for this requirement.

Finally, with regard to your comment on R6.5, there is no preclusion to using RAS or UVLS programs for load shedding. The sub requirement speaks only to manual load shedding needing to occur after all other actions are taken. RAS and UVLS are not manual load shedding. The SDT has included "manual" to FAC-011-4 R6.4 to clarify that automatic load shedding schemes would not be used to meet performance criteria and that load shed is a measure of last resort. The use of UVLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA supports the comments submitted by MRO.

Likes 0	
Dislikes 0	

Response

Please see response to MRO.

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

American Transmission Company LLC (ATC) supports the efforts of the SDT to clarify for the industry what is considered SOL exceedance in the context of the IRO and TOP Standards. We appreciate the SDT listening to the concerns raised by industry regarding the previously proposed SOL Exceedance definition and we agree with the SDT's approach to abandon that potential change. We believe the proposed performance criteria in FAC-011-4 Requirement R6 seems to capture the essence of SOL exceedance. We do agree with the SDT's concept that the Reliability Coordinator's (RC) SOL Methodology must address the system performance criteria to ensure consistent identification of SOLs.

However, ATC is concerned the proposed language creates a significant reliability/compliance burden for RCs and Transmission Operators (TOP) as follows:

- R6.2 - The language mandates evaluation of all contingencies listed in R5.1.1 of FAC-011-4 as part of the Real Time Assessment (RTA) and the Operational Planning Analysis (OPA) without exception. When coupled with R6.2.3, this language pulls in dynamic analysis of all of these contingencies for both the RTA and OPA. This is an infeasible expectation for the RC and TOP to include in their RTAs and OPAs, since R5.1.1 contains no caveats to limit the list of applicable single contingencies.
- R6.2.1 - The flows on a transmission element may exceed the applied Emergency Rating during the dynamic time period, but there is likely no risk to the system. Although the first phrase "applicable Emergency Ratings" might seem to provide the flexibility, this means an entity must know the *"applicable Emergency Rating"* for a particular dynamic loading and time period for each piece of equipment and each piece of equipment would need to be monitored in a dynamics analysis. It may be that the SDT does not intend to pull in dynamics in 6.2.2 but it is a logical reading of the standard.
- R6.2.3 - As noted above, although this is the desired result, it is infeasible to perform dynamic analyses of all R5.1.1 contingencies as part of either an RTA or an OPA. In fact, it is an extremely expensive proposition to perform any real time dynamic simulations due to the complexities of maintaining an accurate dynamic model that incorporates traditional transmission equipment let alone the myriad of user written or proprietary dynamic models in use today for FACTs devices and variable generation.
- R6.3 and R6.4 contain the same problems as noted above. It is infeasible to run dynamic simulations as part of the RTA and it is very complex to do so for the OPA. At least in this case, R5.2 and R5.3 allow the RC to provide a very limited list of contingencies. Still, even with a limited list, the language of R6 and its sub-parts does not limit the scope of what a TOP would be required to run under FAC-014-3 (see R2 of that standard). Rather, FAC-011-4 R6 language implies that a TOP would be required to evaluate all of the contingencies identified by an RC, not just those that apply to the TOP's footprint. Note that FAC-014-3 R2 limits the TOP to identifying SOLs to its footprint, but it does not limit the contingencies a TOP would need to consider.
- R6.5 - The standard incorrectly eliminates planned load shedding from consideration when a RAS or UVLS programs may have specifically established the need to take such action to maintain system stability for the particular contingencies under consideration.

ATC offers the following proposed improvements to address the comments above:

- R6.1.1, R6.1.2, R6.2.1 and R6.2.2 could be improved by clarifying that these sub-requirements are only describing steady-state conditions. Each requirement could have the following leading statement added: "*Under steady-state analysis:*".
- In addition, R6.2.1 and R6.2.2 would also benefit from adding the word "*Anticipated*" ahead of the terms "*Flow*" and "*Voltages*" in these requirements, respectively, to make it clear that these are potential system flows and voltages, not real time flows and voltages, being evaluated.

Regarding the scope of dynamic simulations, the best location to make modifications is likely the R5 and R5.1 language, not R6. Proposed modifications are as follows:

- R5 - Strike "*and performing the Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study*" since this language is redundant to the R6 performance criteria language that will require these contingencies to be evaluated as part of the RTA and OPA. With this removed, R5 is tailored to only describe what contingency events need to be examined for the identification of SOLs.
- R5.1 - Remove the language regarding "*determining stability limits and performing OPAs and RTAs*" and add "*for use in determining steady state SOLs*", since the SOL methodology should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to R5.3.should require examination of all of the single contingencies listed under R5.1.1 using steady-state analysis. The contingencies to examine for dynamics will be a very small list (hopefully) and can be adequately addressed by modifications to R5.3.
- R5.2 - Remove "*for use in performing Operational Planning Analysis and Real-time Assessments*" since, again, this is adequately covered by R6, and add in language as follows "*for use in determining steady state SOLs*".
- R5.3 - Strike the word "*additional*" from the existing R5.3 language and add the following to the end of the requirement: "*where the identified single Contingency events involving the loss of a generator, transmission circuit, transformer, shunt device, or single pole block in a monopolar or bipolar high voltage direct current system must simulate either: (a) Normal Clearing of a single phase to ground or three phase Fault (whichever is more severe) or (b) tripping without a Fault condition*".

- Regarding the TOP performing a certain set of contingencies, the R6.2, R6.3 and R6.4 language could all be modified to state: *"The evaluation of applicable potential single Contingencies …"* (for R6.2) and *"The evaluation of the applicable potential Contingencies …"* (for R6.3 and R6.4).
- R6.5 could be improved by clarifying that RAS and UVLS actions should be implemented in the stability analysis, as applicable. The SDT should also recognize that underfrequency load shedding (UFLS) may be a necessary part of system stabilization once a RAS operates if that RAS is creating a planned islanded system. As such, UFLS may also be a warranted load shedding component when performing stability analysis. R6.5 language could be modified by adding *"planned load shedding, other than Remedial Action Scheme (RAS) or UVLS action, is acceptable …"* and then adding a new sentence that reads, *"The use of UFLS programs should only be simulated when incorporated as part of the system design to maintain stability (e.g., RAS)."*

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments you have provided. The SDT has made several edits to R4, R5, and R6 and their subparts that the SDT believes addresses many of the comments.

The SDT has revised the sub requirement in R4.2 to clarify that a subset of Contingencies may be used that are expected to produce more severe System impacts on its portion of the BES.

The SDT has revised the sub requirements in R6 that deal with stability and have tried to remove that text which implies a need to perform real-time stability analysis. It is not the intent of the SDT to require any entity to perform real-time stability analysis as part of their Real Time Assessments.

Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture that "planned manual load shedding", if included in an Operating Plan, should be a measure of last resort. With respect to RAS, requirement R4.6

requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations". However, R4.7 requires "that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits". The use of UVLS and UFLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

The criteria given are not clear as written such that they appear to occur in the Real-time horizon and apply to real-time operations rather than in the Operations Horizon as stated. As a consequence, the criteria do not seem to meet a methodology requirement but an operating one. Specifically, the identification of real-time monitoring and assessment as a demonstration is inappropriate for a FAC methodology requirement and belongs in TOP and IRO standards relating to operations. We believe there should not be an operating requirement in FAC-011 and in our opinion this is a poor practice and should be shelved. The Standard "families" set certain expectations and should be respected because to do otherwise will create risks of inconsistency. If the TOP and IRO standards need amending, then amend them!

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments you have offered. Your comments about applicability of the performance criteria to either the FAC or TOP/IRO standards is one made by numerous entities. The SDT has discussed this at length, while considering that the existing FAC-011-3 has performance requirements (R2 and sub requirements), no specificity exists in the present TOP and IRO standards regarding thermal, voltage and stability performance, other than stating that SOLs must be respected and SOLs exceedances acted upon, while not definition of SOL exceedance exists. Since SOL exceedances (or potential ones) can be determined from the Operational Planning Time Horizon up to and including Real Time, the SDT thought having a single common set of requirements for SOL exceedances made sense. If those existing in the TOP and IRO standards for real time, then they would have to exist for outage coordination and operating planning analyses. Rather than

include duplicates of language for SOLs throughout the TOP and IRO standards, the FAC SDT sought to include in one location, the RC methodology, the verbiage used to define SOL exceedances for the entire RC footprint. To a certain extent, that is already done with existing R2 in FAC-011-3. The SDT's revised FAC-011-4 R6 proposes to have the RC define SOL exceedances using a common initial basis with the performance criteria in the sub requirements of R6. This application seems consistent with what an SOL methodology should contain, and currently does for many RCs at present. The SDT has however proposed modifications to IRO-008 and TOP-001 to coordinate between those two standards and FAC-011-4. The SDT believes these modifications best address the noted concerns in a balanced fashion with other comments and feedback while maintaining some amount of flexibility for the RC in the SOL methodology.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP is concerned the language in 6.5 may be too limiting, specifically the phrase "only after **all** other available System adjustments". SRP suggests either adjusting the language to state "after other reasonable System adjustments have been made", or to state "while other system adjustments are being made". It may be necessary to respond first with load shed while other system adjustments are being made, then returning the load. The language should allow entities to use all available tools and determine the best process for maintaining stability of the system. Also, SRP recommends retaining some of the language in FAC-011-3 R2.3 and R2.4 explicitly identifying acceptable post-Contingency actions. Consideration of post-Contingency actions is appropriate in an SOL methodology because the available actions delineate the "specified System configuration". Furthermore, including the language in the standard and as a result in the RC's SOL Methodology, helps ensure the performance criteria in the Operations Horizon is not more limiting than the performance criteria used in the Near-term or Long-term Planning Horizons.	
Likes 0	

Dislikes 0	
Response	

The SDT appreciates your comments. The SDT discussed language choices on proposed R6.5 at length. The first option you offered with the word "reasonable" was thought to be subjective, and not language that should be in a standard. The second option you offered, "while other system adjustments are being made" again seemed to suggest load could be shed when there were other options that could be deployed to preclude the load shed, for example, dispatch of uneconomic generation.

The SDT chose the language it did in the proposed sub requirement to emphasize that manual shedding of load should be done as a matter of last recourse. This does not include planned RAS or UVLS, which would have been examined with other options by the operating entities. If conditions do not allow the application of alternatives, then of course load can be shed to maintain system reliability. In this respect, the SDT agrees with your comment that load may have to be shed before other actions can be taken. This language removes no tools for maintaining system reliability; it merely states that manual load shed should be used only after exhausting all other options. Additional description is offered in the posted rationale.

With regard to your comment to retaining language from FAC-011-3 R2.3 and R2.4, proposed R6 retains the option to shed load. Existing R2.3.1 goes without saying except for the final phrase "or by the affected area"; radial or faulted elements result in lost load when those elements are lost. R2.3.2 is a less specific, more flexible way of stating what the SDT did in R6. The SDT did not believe there was a need to describe how an operating entity operates the system as FAC-011-3 R2.3.3 and R2.4 attempt to do.

Finally, with respect to your comment that performance criteria in the Operations Horizon is no more limiting than that in the Planning Horizons, it is not the SDT's opinion that the language proposed in R6, or any other portion of FAC-011-4 supports that position. It is our understanding that the RC is the ultimate authority for operating criteria just as the PC is the ultimate authority for planning criteria, and FAC-011 is not the mechanism by which to coordinate the two sets of criteria.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	
Comment	

ITC agrees with MEC and believes that addressing the fundamental concept of defining SOL Exceedance needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. We do not agree with the approach of moving that cornerstone of reliable operations from IRO/TOP set of standards to the FAC set of standards. In other words, we believe that the present context of defining what constitutes SOL exceedance and reacting to it by initiating an Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

The FAC standards should facilitate the creation of SOL's, not define operating criteria. SOL's should; (1) at a minimum be equal to Facility thermal or voltage limits and (2) consider system stability (voltage or transient) limits that may require limits more restrictive than Facility thermal or voltage limits.

The FAC standards should in no way infer that dynamic analysis needs to be performed as part of RTAs. Requirement R6 of FAC-011-4 as currently written could be inferred to require real time dynamic analysis. Specifically, it is unclear if requirements R6.1.3, R6.2.3, R6.3 and R6.4 require that RTA's include dynamic analysis to determine if Instability would occur or if operating to the pre-identified SOL's would provide this determination.

ITC agrees with MEC that the phrase "could be executed and completed within the specified time duration" throughout requirement R6. This could be interpreted as requiring a timing analysis before the contingency occurs to determine if ramp rates, start-up times and location and amount of load shedding are adequate. The implementation risk and compliance risk associated with this language is substantial and very concerning. Based on the language, TOP is expected to perform and document a timing analysis to determine if the adjustments could be executed within the specified time duration of Emergency Ratings each and every time when TOP performs RTA and find its facilities operating between Normal and Emergency Rating (either in real-time or on a contingency basis). It should be noted that such a timing analysis in real-time is difficult and requires significant time and resources.

Instability, as used throughout the existing standards is an undefined term which leaves room for broad interpretation. This term should be removed or defined to clarify that single unit instability would not constitute “instability” as it is used in these proposed standards.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments you have provided. The SDT received similar comments with regard to where in the standards to implement some form of SOL exceedance definition or determination. While the TOP and IRO standards may seem to be the appropriate place, the current standards have no standard which requires a uniform method be used between an RC and its TOPs when defining SOL exceedances. Furthermore, the cited existing requirements (TOP-001-4 R14 and IRO-008-2 R2) merely state merely have an operating plan to use when SOL exceedances are identified with no mention of how those SOL exceedances are determined. The SDT has however proposed modifications to IRO-008 and TOP-001 to coordinate between those two standards and FAC-011-4. The SDT believes these modifications best address the noted concerns in a balanced fashion with other comments and feedback while maintaining some amount of flexibility for the RC in the SOL methodology. The SDT, through our three years of discussion and industry consultation, believe it is appropriate that each RC have a defined SOL exceedance determination methodology for use within its footprint. In addition, the broad outlines of what may constitute an SOL exceedance, per the proposed R6 and its sub requirements, seemed a reasonable place for each RC to use as an initial basis when developing their SOL exceedance method since the existing FAC-011-3 R2 requires the system to be “within their Facility Ratings and within their thermal, voltage and stability limits (R2.1)”. The SDT has revised the sub requirements in R6 that deal with stability and have tried to remove that text which implies a need to perform real-time stability analysis. It is not the intent of the SDT to require any entity to perform real-time stability analysis as part of their Real Time Assessments. In addition, the SDT has removed or changed the wording dealing with “the specified time duration” and more generally applied the appropriate limits for the condition (thermal or voltage) in question.	

Finally, the SDT used the word “instability” as it is currently used in the definition for IROL as found in the NERC glossary of terms. The SDT will consider adding a clarifying phrase to limit the instability consideration to the BES.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE has concerns with the performance criteria specified in FAC-011-4 Requirement R6. As an initial matter, until FAC-014-3 Requirement R6 is read, it isn't understood that the performance criteria in FAC-011-4 R6 is referring to SOL exceedances.

That said, Texas RE is concerned that the way the performance criteria is written, and that an SOL exceedance would not occur until the highest Emergency Rating is exceeded. Therefore, the RC and TOP may not develop an Operating Plan for exceedances of the Normal Rating identified through the OPA (TOP-002-4 and IRO-008-2), and would not be required take action to return flow to Normal Ratings when Real-time flows exceed the Normal Rating (TOP-001-4), since there is no exceedance occurring in the Parts 6.1 and 6.2 scenarios:

- FAC-011-4 Part 6.1 - Operating Plans should be created anytime the anticipated pre-Contingency state (Operational Planning Analysis) demonstrates flow above the normal Rating or voltage outside of the normal System Voltage Limits. Additionally, Operating Plans should be initiated when the actual pre-Contingency state (Real-time monitoring) identifies flows or System Voltage Limits exceeding the normal Rating.
- FAC-011-4 Part 6.2 should still require entities to create an Operating Plan that is available to System Operators if evaluation of potential single Contingencies listed in Part 5.1.1 against the anticipated pre-Contingency state (Operational Planning Analysis) indicates flow above normal Ratings. There is no way to know if System adjustments could be executed within time duration of Emergency Ratings without creating an Operating Plan to address the issue, and identifying a time-frame in which the Operating Plan could be executed. Since FAC-014-3 R6 states determination of SOL exceedances during the OPA is required to be in accordance with RC SOL Methodology, this language would not require a the creation of an Operating Plan to mitigate an exceedance of the normal Rating that is identified during the OPA.

- Real-time flows may legitimately exceed Normal Ratings as a result of conditions unanticipated by OPA, initiating the use of Emergency Ratings and their associated time limits in order to return flows to below Normal Ratings without an Operating Plan. This is the intended purpose of Emergency Ratings. It is unrealistic to assume that all operating conditions are captured by OPA, as OPA is based on preconceived contingent states.
- The same does not hold true for “anticipated pre-Contingency states” based on OPA. An anticipated pre-Contingency overload beyond the Normal Rating indicated by OPA is a base case overload which requires mitigating actions or an Operating Plan before the condition which would cause the overload occurs. Using Emergency Ratings and their associated time limits for this situation is not their intended purpose.

RCs and TOPs should be prepared when flow is outside of Normal Ratings. In order to maintain reliability, Texas RE recommends immediate action through the use of an Operating Plan to mitigate any flows or voltages outside the Normal ratings or System Voltage Limits.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments. The SDT has made several edits to R6 based on industry comments. The SDT has, however, preserved the understanding identified in the SOL whitepaper that pre-contingency flow beyond a Normal Rating but below an Emergency Rating for a finite period of time less than the associated time with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be required to constitute an SOL exceedance. Similarly post contingency flow beyond a Normal Rating but below an Emergency Rating for which there is reasonable time to address the exceedance before the finite period of time associated with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be required to constitute and SOL exceedance. Nothing precludes an RC from applying more conservative criteria such as that as described by Texas RE’s comments, however, this standard would not require such performance criteria.

The SDT understands the comments surrounding the OPA and Operating Plans and real time conditions, however the SDT is focusing responses on the subject matter of FAC standards and not the corresponding IRO/TOP standard requirements and what constitutes an acceptable Operating Plan.

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

Southern California Edison (SCE) believes that the NERC Standard Drafting Team approach of defining SOL Exceedance through a performance criteria in Requirement 6 of FAC-011-4 is inappropriate. If the Standards Drafting Team decides to include the undefined term "SOL Exceedance" within the performance criteria of FAC-011-4, the SDT effectively exposes a number of TOPs and RCs to the risk of violating FAC-011-4 (Requirement 6) if/when exceedances of system operating limits occur either in RTA or OPA. SCE believes that NERC should mitigate the regulatory uncertainty of using the undefined terminology within the performance criteria of FAC-011-4, and create a standard definition of SOL Exceedance. SCE is particularly sensitive to this issue due to Peak RC ceasing operations in 2019.

Additionally, SCE believes NERC should create a definition for "SOL Exceedance" by using existing framework of IRO and TOP standards. SCE believes that the present context of defining what constitutes SOL exceedance and reacting to it by initiating Operating Plan (per IRO-008-2-R2 and TOP-001-4-R14) is far better than directly exposing large number of entities to the risk of non-compliance without appropriate considerations related to physical constraints that need to be overcome during implementation of Operating Plans, in a timely manner.

Finally, SCE supports the examples presented by MidAmerican and the MRO NSRF that demonstrate the unintended consequences of using the undefined term "SOL Exceedance" within FAC-011-4 Requirement R6.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments. The SDT notes your comments, however a previous attempt to create a definition for SOL exceedance received feedback that a majority of the commenters did not agree the proposed definition and that a definition was not needed. The SDT has chosen to use a similar approach to the current FAC-011-3 which specifies system performance criteria and allows the RC to define what constitutes an SOL exceedance for its RC Area so long as it meets or exceeds the system performance criteria.

Randy MacDonald - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Does planned load shedding include automatic load shedding schemes such as UVLS? Within the operational time frame UVLS should be allowed.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has included "manual" to FAC-011-4 R6.4 to clarify that automatic load shedding schemes would not be used to meet performance criteria and that load shed is a measure of last resort. The use of UVLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
In 6.1.1 and 6.1.2, use of emergency ratings and emergency voltage limits seems inappropriate during pre-contingency states. Recommend re-phrasing 6.1.3 and 6.2.3 to "a state that leads to instability, uncontrolled separation, or Cascading" in order to be more consistent with existing definitions, such as IROL and Reliable Operation, that use the terms instability, uncontrolled separation, and Cascading.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments. The SDT has, however, preserved the understanding identified in the SOL whitepaper that pre-contingency flow beyond a Normal Rating but below an Emergency Rating for a finite period of time less than the associated time with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be required to constitute an SOL exceedance. Similarly post contingency flow beyond a Normal Rating but below an Emergency Rating for which there is reasonable time to address the exceedance before the finite period of time associated with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be required to constitute and SOL exceedance. Similarly, many entities may utilize time based emergency voltage limits that allow for graduated actions to be taken based on the time exceeded. Nothing precludes an RC from applying more conservative criteria. The SDT has chosen to include the verbiage as "instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System do not occur" rather than tying the performance criteria to a state rather than the performance itself.

William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
In 6.1.1 and 6.1.2, use of emergency ratings and emergency voltage limits seems inappropriate during pre-contingency states. Recommend re-phrasing 6.1.3 and 6.2.3 to "a state that leads to instability, uncontrolled separation, or Cascading" in order to be more consistent with existing definitions, such as IROL and Reliable Operation, that use the terms instability, uncontrolled separation, and Cascading.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has, however, preserved the understanding identified in the SOL whitepaper that pre-contingency flow beyond a Normal Rating but below an Emergency Rating for a finite period of time less than the associated time with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be required to constitute an SOL exceedance. Similarly post contingency flow beyond a Normal Rating but below an Emergency Rating for which there is reasonable time to address the exceedance before the finite period of time associated with the Emergency Rating (e.g. 2 hours) is acceptable system performance and thus would not be	

required to constitute and SOL exceedance. Similarly, many entities may utilize time based emergency voltage limits that allow for graduated actions to be taken based on the time exceeded. Nothing precludes an RC from applying more conservative criteria. The SDT has chosen to include the verbiage as "instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System do not occur" rather than tying the performance criteria to a state rather than the performance itself.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SME: The criteria seems appropriate and in line with TPL criteria.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We are in general agreement over the proposed changes as they essentially maintain the system performance criteria, similar to the approach in the currently effective FAC standards. Our main comments are:	

- The proposed standards should require the Reliability Coordinator's (RC) methodology to establish stability limits when those limits also impact other RC Areas, and that the criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied.

- Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognized that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. However, this falls short of requiring an entity to determine new/revised limits to begin with. Without knowing the boundaries, performing real-time analysis every 30 minutes does not give the entity an indication if current operations (power flow or voltage levels) exceed the limits that are valid and applicable for the present conditions. These conditions pose unacceptable risks of instability since the operator does not know whether the next contingency will result in system instability.

We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.

Likes 0	
Dislikes 0	

Response

Response

The SDT appreciates the comments. The SDT has added to FAC-011-4 R4.3 the phrase "or other Reliability Coordinator Areas." The SDT recognizes the comments surrounding the retirement of TOP-004-2 R4, however the SDT is focusing responses on the subject matter of FAC standards and not the corresponding IRO/TOP standard requirements and would direct the commenters to previous responses to similar

comments issues as part of that Project 2014-03 SDT as those comments attempted to address the concerns noted. The SDT reaffirms its scope to focus on the SOL methodology and subsequent required content and performance criteria contained within.	
Answer	Yes
Document Name	
Comment	
GTC agrees with the SDT's proposal and has one suggested wording modification the Requirement R6, Part 6.2.1. 6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest applicable Emergency Rating.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT modified 6.2.1 to address other comments as well and now reads, "Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating." The use of "applicable" was not chosen as "highest" was intentionally chosen to mean the highest Emergency Rating and is consistent with the SOL whitepaper.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	Yes
Document Name	
Comment	

We are in general agreement over the proposed changes as they essentially maintain the system performance criteria, similar to the approach in the currently effective FAC standards. Our main comments are:

· The proposed standards should require the Reliability Coordinator's (RC) methodology to establish stability limits when those limits also impact other RC Areas, and that the criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied.

· Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognized that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of an RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. However, this falls short of requiring an entity to determine new/revised limits to begin with. Without knowing the boundaries, performing real-time analysis every 30 minutes does not give the entity an indication if current operations (power flow or voltage levels) exceed the limits that are valid and applicable for the present conditions. These conditions pose unacceptable risks of instability since the operator does not know whether the next contingency will result in system instability.

We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments. The SDT has added to FAC-011-4 R4.3 the phrase "or other Reliability Coordinator Areas." The SDT recognizes the comments surrounding the retirement of TOP-004-2 R4, however the SDT is focusing responses on the subject matter of FAC standards and not the corresponding IRO/TOP standard requirements and would direct the commenters to previous responses to similar comments issues as part of that Project 2014-03 SDT as those comments attempted to address the concerns noted. The SDT reaffirms its scope to focus on the SOL methodology and subsequent required content and performance criteria contained within.	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

We support the FAC revisions.

We have the following comments:

Subrequirements R7.1 andR 7.2

We agree with comments submitted by the NPCC RSC in regards to requirements 7.1 and 7.2. The subrequirements R7.1 and R7.2 require the identification of SOL that are IROL and the criteria for identifying SOL violations that are IROL. We do not understand the difference and our compliance department do not see how the evidence of those two subrequirements would be distinct.

Requirement R5.1

We have a minor comment regarding the addition in R5.1 of "Specify the" makes the use in 5.1.1 of "any" more ambiguous than it is in the current version. Consider that R5 now requires

a) identify in its SOL methodology…

b) Specify the following single contingency event…

c) Loss of "any" of the following.

Before it clearly "included" the following "list" of single contingency events. It would be better for the language to clearly state in 5.1.1. "Loss of each of the following" or return to language that clearly mandates the inclusion of the loss of all the listed elements. Requirement 9 Also, the last sentence of the Rationale for Requirement R9 for FAC-011-4 should be modified as follows. "(…) mandates provision of the SOL Methodology to non-adjacent RCs [or to adjacent RCs in another Interconnection] that have specifically requested (…)"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. With regard to your query on subrequirements R7.1 and R7.2, those exist in today's FAC-011-3 as R1.3 and R3.7. They have been included, unchanged, from the existing FAC-011-3 other than being relocated to single common standard (R7). If you wish to propose a revision, perhaps joining the two subrequirements (maybe something like "A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), including the criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL Tv."), please do so. Regarding your question on R5.1 and R5.1.1, the drafting team made the revisions as shown to provide the flexibility for contingency lists created for stability analysis to not have to examine every single facility contingency when engineering judgement would allow the contingency list to be distilled down to the likely most limiting. Real time steady state analysis could and should use a contingency list that includes most of the single element contingencies, but even that list could exclude a subset of contingencies that could not be most limiting, for example loss of a small load serving transformer or a small generator. Finally, with regard to requirement 9, we included subrequirement 9.1 so that any RC could request an RC's SOL methodology and subrequirement 9.2.4, which allows any RC to request another RC's SOL methodology, should there be a reliability based need, before it becomes effective. These two subrequirements should allow adjacent RCs in another interconnection to request the appropriate SOL methodology of their choice.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

SCE concurs with MidAmerican's additional comments regarding FAC-011-4.	
Likes 0	
Dislikes 0	
Response	
See response to MidAmerican.	
Randy MacDonald - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
Regarding R3.3 What is the purpose of this subrequirement? The methodology should not prevent or limit the use of undervoltage load shedding by the Reliability Coordinator in the operational time frame. Suggest changing the wording to allow for undervoltage load shedding within the operational time frame as long at the reliability coordinator is aware. The methodology could have the requirement that the use of UVLS requires RC approval.	
Likes 0	
Dislikes 0	
Response	
We appreciate your comment. This subrequirement (R3.3) was derived after much drafting team and observer discussion. The consensus was that while under-voltage load shedding (UVLS) schemes can be useful, they should not be the premise upon which acceptable system performance is solely based. When there are other operating actions which can be taken, such as dispatch of generation, those actions should be taken, while the under-voltage load shedding schemes can act to mitigate unexpected poor system performance should it occur. As an example, if the lowest acceptable post-contingent voltage was 90% of nominal, the UVLS scheme could have an actuation voltage setting of 89% of nominal.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	

Answer	
Document Name	
Comment	

Numbering typos exist in Measure Nos. M7, M8, and M9. Requirement Nos. R7, R8, and R9 should be referenced accordingly.

Revised language in Requirement R1 is not included in the Violation Security Levels table. Specifically, the term “documented” was added to Requirement R1. ERCOT suggests including the term in the Violation Severity Levels table order to be consistent.

Similarly, the revised language in Requirement R2 is not included in the Violation Security Levels table. Specifically, “the applicable” was replaced with “which” and “are” in Requirement R2. ERCOT suggests including the same revisions in the Violation Severity Levels table.

In requirement R9, “and any changes to the SOL Methodology prior to the effective date of the SOL Methodology” was deleted. ERCOT suggests aligning the Violation Severity Levels table to align with this revision and the specific language of the applicable requirements. For Part 9.1, there is no distinction between “new or revised” in the wording of the requirement, but it is explicitly stated in the Violation Severity Levels table.

ERCOT suggests capitalizing “methodology” in Requirement R9, Part 9.2.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. We will review the language in measures 7, 8 and 9 and revise accordingly. Similarly, we appreciate your comments on the Violation Security Levels table and will make the appropriate editorial changes.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed FAC-011-4 Part 3.3 uses the term "under voltage" while the NERC Glossary and other Standards use the term "undervoltage".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We will include the appropriate term in the version posted for ballot.	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
Requirement R2 specifically states that the RC "shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations". This requirement needs to be bounded such that the RC is not specifying in its methodology how a Transmission Operator and thus a Transmission Owner is required to rate its transmission facilities, up to and including the use of real time ratings. This would determine the amount of risk a Transmission Owner is subject to for its facilities. The standard should only specify the end objective and not the process to achieve that objective.	

Requirement R8 is redundant with IRO-010-2 R1. SOLs are inputs to OPA and RTAs. As such, R1 of IRO-010-2 already requires the RC to maintain a documented specification of the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring and Real-time Assessments. This requirement included requirements for periodicity of providing the data. As such, R8 of proposed FAC-011-4 is redundant and should be deleted from the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in requirement R2 was chosen to allow the RC to describe how it wishes the TOP to use the facility-owners ratings to meet the rating needs of the RC. The RC is allowed to determine what it needs for rating information to function. By doing so, the RC does not dictate to either the facility owner now TOP what ratings need to be provided. For example, the RC may state it wants a normal rating and a 1 hour emergency rating. Per requirement R2, the RC may instruct the TOPS, through its SOL methodology, that it wishes to have its rating set filled with the rating whose time duration most closely approximates the desired duration of the RC's rating, with the rating chosen always having a time duration at least equaling that of the RC's rating. Therefore, if the facility owner provided ratings for 24 hour, 2 hour and 30 minutes, the TOP would use the 24 hour rating for the normal rating and the 2 hour rating to meet the RC's 1 hour rating. This example illustrates how the RC describing how the facility ratings may be used to meet the RC's rating needs does not determine how the facility owner rates equipment.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	

FMPA is concerned that Project 2015-09 does not consider the work done by the MEITF (Methods for Establishing IROLs Task Force). There are defined terms used in R6 that the MEITF has proposed changes to, and that have been endorsed by the NERC PC and OC. FMPA asks that the implementation plan be changed so that FAC-011-4 would only be effective once the new definitions proposed by the MEITF become effective

Likes 0	
Dislikes 0	

Response

We thank you for the comment. The drafting team, in consultation with NERC, have decided that the work, and terms, defined by the MEITF, as well as the IROL topic, can wait while the FAC standards that are within scope of the drafting team are resolved. It is the opinion of the SDT and NERC that the terms defined by the MEITF are not needed to revise FAC-011.

Douglas Johnson - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

ATC does have other comments on FAC-011-4:

- Requirement R3 addresses the establishment of a voltage-based SOL at each bus. No similar requirement is given for thermal ratings. It is unclear if the SDT expects each Facility to have a thermal-based SOL. Alternatively, can TOPs and RCs use multi-element or proxy flowgates to manage power flow on the system? The expectation regarding thermal related SOLs needs to be clearly stated in any requirement such that entities can fulfill the requirements and all entities are operating the BES from the same understanding.
- R3.3 should be improved by clarifying what undervoltage load shedding (UVLS) systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by UVLS relay settings implemented by a distribution utility or an end-use customer. A suggested edit is to clarify these are BES systems as follows: "*in-service BES relay settings for undervoltage load shedding…*".

• Similar to comments provided in question #1 related to R6.5, Requirement R4.7 should be modified to remove the restriction on using UVLS Programs when setting stability limits. It is generally accurate to state that UFLS should not be relied upon to maintain stability, although the SDT needs to recognize that UFLS may be a necessary component to maintain stability of a portion of a system deliberately islanded by a Remedial Action Scheme. As such, R4.7 should be modified to read, *"State that the use of underfrequency load shedding (UFLS) programs are not allowed in the establishment of stability limits except in specific, documented circumstances (e.g., Remedial Action Schemes)."*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The wording of requirement R2 in FAC-011-4 is such that the RC is setting a method for adoption of ratings for all elements for which the facility-owner provides thermal ratings. This is done with the expectation that the RC models and uses thermal ratings for each system element with a rating provided. With that said, there is no preclusion that prevents the TOP or RC using a multi-element or proxy flow gate to assist in maintaining reliability, as long as the provided ratings are used also, and respected in at least their Real-time monitoring, Real-time Assessments, and Operational Planning Analyses. With respect to your comment on subrequirement R3.3, we have adopted your language suggestion. Finally, with respect to your comment on using UVLS and UFLS on setting stability ratings, the SDT discussed both at length. With regard to UVLS, and the setting of traditional stability limits, such as those recognizing angular stability, shedding load via UVLS will not improve stability but instead will either do nothing or exacerbate the concern, so UVLS is not a solution to unit / angular stability nor transient voltage recovery. The preclusion for using UFLS has to do with maintaining stability on the interconnected BES and not disconnected islands, so the standards as proposed do not apply to individual islands created as a consequence of system events, and as such, do not speak to UFLS use within those created islands.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	

Answer	
Document Name	
Comment	
R3.3 Require that System Voltage Limits are higher greater than or equal to in service relay settings for under voltage load shedding (UVLS) relay settings systems and Undervoltage Load Shedding Programs R3.3 should be improved by clarifying what under voltage load shedding systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by under voltage load shedding relay settings implemented by a distribution utility or an end-use customer	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3.3 was written with the thought that System Voltage Limits will not be changed, but instead the settings should be reviewed and changed to not be in conflict with the System Voltage Limits.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	
Document Name	
Comment	
We offer the following specific comments: Sub-Requirement R4.1.3:	

It is not clear what is meant by "unit" stability. We suggest reverting back to using the current term "angular" stability as it is a term well understood by the industry.

Sub-Requirement R4.3:

A main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Sub-Requirement R4.3 to establish SOLs that impact on the Interconnection:

"Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirements R5.2 and R5.3

Sub-Requirements R5.2 and R5.3 require the RC to identify any additional single or multiple Contingency events. We believe that specifying, at a minimum, which contingencies must be respected (similar to Sub-Requirement R5.1.1. for single Contingencies) would improve reliability. In particular, to the extent there is an alignment in respecting the same set of contingencies and performance criteria for IROLs.

Furthermore, the loss of small or radial portions of the system should be acceptable provided the performance requirements are not violated for the remaining bulk power system.

Sub-Requirement R6.2.2

Sub-Requirement R6.2.2 should include the same wording as sub-requirement 6.1.2:

"Voltages are within normal System Voltage Limits; however, emergency

System Voltage Limits may be used when System adjustments to return

the voltage within its normal System Voltage Limits could be executed

and completed within the specified time duration of those emergency System Voltage Limits."

Sub-Requirements R6.3 and R6.4

For consistency purposes, we recommend that Sub-Requirements R6.3 and R6.4 also require to demonstrate that flow through Facilities are within Normal Ratings, similar to Sub-Requirements 6.1.1 and 6.2.1:

"Flow through Facilities are within Normal Ratings; however, Emergency

Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings."

Sub-Requirements R7.1 and 7.2

Sub-requirements R7.1 and R7.2 require to describe how to identify IROLs, and to identify the criteria for IROLs which is basically the same thing. We recommend merging these sub-requirements into one:

7.1. A description of the criteria to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs) and for developing any associated IROL Tv.

R3

Sub-Requirement 3.5 combines two requirements, (1) require a method for determining… and (2) require common use. Sub-Requirement 3.5 should be re-written as "require a method for determining…" as shown below.

We assume that 3.6 and 3.7 intend to "address coordination" within the "method for determining" the limit. As such, that consideration should be rolled into the requirement for "a method for determining.."

Since System Voltage Limits are SOLs, it is unnecessary to explicitly require the operation within the restrictions of System Voltage Limits. Also it is inappropriate to place any system operation requirement (Require the use…) within an operating parameter development methodology. There are already requirements for the system to always be studied and operated within the SOL restrictions of the local reliability entity as well as the SOL of adjacent reliability entities. All requirements for "require the use of common" should be deleted.

3.5 Provide the method for determining the common System Voltage Limits in coordination with adjacent Reliability Coordinators and Transmission Operators.

R4

What is the point of R4.2? If R5 requires that all stability analysis to evaluate the contingencies listed in "5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs." How can one violate 5 without also violating 4.2? Is this not double jeopardy? The identical requirements are applied to both general SOL stability analysis and OPA/RTA stability analysis. R4.2 is a requirement to comply with R5.1.

Sub requirements 5.3 and 5. 4 are double jeopardy and should be deleted. How can there be any contingencies used “determining the stability limits to be used in operations” that are not completely identical to the contingencies used in “determining stability limits and performing OPAs and RTAs.” It is impossible to violate 5.3 or 5.4 without simultaneously violating 5.2

We suggest the SDT Re-write 4.2 determining the stability limits to be used in operations as follows and eliminate R5 its entirety.

4.2 Specify the following single Contingency events for use in determining stability limits

4.2.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

• generator;

• transmission circuit;

• transformer;

• shunt device; or

• Single pole block, with Normal Clearing, in a monopole or bipolar high voltage direct current system.

4.2.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-time Assessments.

R5

What is the point of R5.2? If 5.2 requires that all stability analysis to evaluate the contingencies listed in “5.1. Specify the following single Contingency events for use in determining stability limits and performing OPAs and RTAs.” How can one violate 5.1 without also violating 4.2? Is this not double jeopardy? The identical requirements are applied to both general SOL stability analysis and OPA/RTA stability analysis. R4.2 is a requirement to comply with R5.1.

Sub requirements 5.3 and 5. 4 are double jeopardy and should be deleted. It is impossible to violate 5.3 or 5.4 without simultaneously violating 5.2

Re-write 4.2 as follows and eliminate R5 its entirety.

4.2 Specify the following single Contingency events for use in determining stability limits

4.2.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

• generator;

• transmission circuit;

• transformer;

• shunt device; or

• Single pole block, with Normal Clearing, in a monopole or bipolar high voltage direct current system.

4.2.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-time Assessments.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. We accepted your change and now use "angular" stability. With regard to your comment on subrequirement R4.3, the parent requirement, R4, states that the "Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: . . . " which already makes subrequirement R4.3 subject to the RC's SOL methodology. We believe the suggested text addition is not necessary in R4.3. With respect to your suggested additions to subrequirements R5.2 and R5.3, while the topic was discussed, there was not enough consensus on the topic to include your suggested in the requirements. With respect to your suggested revision for subrequirement R6.2.2, the SDT did not think it appropriate to suggest post-contingent voltages need to be within normal System Voltage Limits. The SDT agreed that emergency System Voltage Limits are appropriate for use in the post-contingent state. The SDT further recognized that emergency System Voltage Limits make take on a variety of forms, with varying potential time applicability, and as such, thought the each TOP / RC would use their emergency System Voltage Limits appropriately as they transitioned the system to a new pre-contingent state to prepare for the next contingency without the need for further language in the standard. The SDT discussed at length new subrequirements R6.3 and R6.4, including which reliability criteria should be applicable. The SDT could only agree that any contingencies included in the RC's contingency list per subrequirement R5.2 should only have to demonstrate the performance described in subrequirement R6.3. RCs are not precluded from having more prescriptive criteria for any contingency they specify per subrequirement R5.2. In addition, subrequirement R6.2.1 already establishes appropriate thermal performance in the post-contingent state and is not required to be restated in subrequirement R6.4. The SDT has accepted your suggestion of combining subrequirements R7.1 and R7.2 into a single requirement. The SDT has revised subrequirement R3.5 to only defining the method to be used to determine voltage limits for the conditions described. Subrequirements R3.5, R3.6 and R3.7 have been combined into a single subrequirement (R3.5). The SDT retained the concept of defining the method for determining common System Voltage Limits found in the old and new subrequirements due to multiple participants in the drafting process noting it as a real operating concern. There is nothing in the subrequirment that mandates the establishment of common System Voltage Limits, and whatever System Voltage Limits results, the most limiting will be respected in operating the system.

Subrequirement R4.2 was established due to numerous comments by industry and members of the SDT. The subrequirment allows an RC or TOP to uses those contingencies that produce the more Severe system impacts when establishing stability limits. Commenters correctly pointed out that without such a subrequirement, all contingencies would have to be tested to establish contingency limits, including those that had no reasonable likelihood of setting a stability limit. Subrequirement R5.1 establishes the minimum contingency list, and subrequirement defines the subset of those contingencies that may be tested to establish stability limits. Subrequirement R5.3 has been removed. Subrequirement has been changed to conform with removing FAC-015 and including a new requirement R7 in FAC-014. The SDT does not believe the revised subrequirement R5.3 is "double jeopardy" in any way; instead, the subrequirement is included so that contingencies identified in annual planning assessments causing stability issues can be evaluated to see if any additional contingencies should be respected in operating the system based upon the supplied information. The subrequirement does not require inclusion of additional contingencies. The subrequirement is based upon information already required for provision in FAC-014-2, subrequirements R6.1 and R6.2.

Laura McLeod - NB Power Corporation - 5	
Answer	
Document Name	
Comment	
Do not agree with R3.3, too restrictive. Should be allowed to have UVLS relays set higher then SOL voltage limits.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment. Your perspective was discussed at length by the SDT with regard to this subrequirement. That discussion, and resulting comments from observers and drafting team members recognized that allowing UVLS relays to actuate above System Voltage Limits would potentially allow a TOP to not take all appropriate actions to remain within System Voltage Limits, which was not believed to be appropriate when operating the system. That is the reason why this subrequirement was written with this choice of language.	

Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
R5.1.1 includes all generators and all shunt devices. There is minimal benefit to attempting to study the impact of the unavailability of every shunt device on the transmission system. Defining some criteria on which shunt devices will be studied would be ideal, to avoid creating an unnecessarily burdensome requirement for studies being performed. RCs should specify their criteria for including these, recognizing the size and potential impact of individual elements, the design of system protection, and the needs of their area.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT revised requirement R5 to state that "Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)." These sets of Contingency events, while based upon the contingency events listed in subrequirements R5.1.1, R5.2 and R5.3, may be adjusted to account for concerns such as the one you describe.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	
Document Name	
Comment	

Recommendation: Replace "Instability" with "System instability"

Proposed FAC-011-4. The companies suggest replacing "instability" with "System instability" to provide context and boundaries to the proposed Requirements.

The companies recognize the word "instability" is used without a modifier in the NERC Reliability Standards and Glossary Terms but equally so, it is used with a modifier to provide a boundary to the word. For example:

- Glossary Term: ULVS Shedding Program, "…leading to voltage instability, voltage collapse…"
- Glossary Term: Adverse Reliability Impact, "…an event that results in frequency-related instability…"
- TPL-001-4 R6, "…system instability…voltage instability…"
- PRC-012-2 R4.1.3, "…angular instability, voltage instability…"
- PRC-024-2 R1, "…instability in power conversion…"

Significant Administrative Burden. The effect of using "instability" without a modifier will require entities to report every single instance of "instability" developed from a significant number of contingency events identified during the annual Planning Assessments, including unit instability under TPL-001-4.

Recommendation 1

Replace "instability" with "System instability" throughout the proposed FAC-011-4 revision. "System instability" is already used in TPL-001-4. Replacing the term provides an effective parameter to reporting by requiring reporting of coordinated instances of instability that necessitate a Correction Action Plan and, in turn, relieve entities of a time-consuming and overly-burdensome reporting requirement.

Recommendation 2

Requirements 6.1.3 and 6.2.3

The companies suggest 30-minute time thresholds, Tv, be added to the proposed revisions to FAC-011-4 R6.1.3 and R6.2.3. This provides RCs / TOPs a time certain threshold to correct exceedance for determinations of compliance.

R6.1.3 and R6.2.3 refer to preventing instability, cascading or uncontrolled separation.

- The present definition of IROL Violation has a Tv time threshold (< 30 minutes) before it becomes a compliance issue.
- The proposed language does not recognize time-frames associated with exceedances of established stability limits.
- Effect: Without a time-frame, it is conceivable a system could experience a significant number of exceedances that possibly last less than 1-minute with a magnitude less than 1%. In such a case, to report would be an onerous compliance burden.

To mitigate potentially over burdensome reporting of a significant number of *di minimis* exceedances, the companies recommend establishing a parameter by requiring reporting of only coordinated instances of instability that necessitate a Correction Action Plan.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT, over its existence, has discussed the very edit you suggest – changing "instability" to "system instability". Since this suggested edit is linked to the topic of IROLs, and this topic did not lend itself to resolution in this phase of the SDT's efforts, the SDT, as suggested by NERC, is deferring the suggested wording change until the topic of IROLs is dealt with after the SDT revises the FAC standards within the scope of its SAR. Your suggested wording revision will be seriously considered in the next phase of the SDT's work.

The SDT did not include any defined Tv within requirement R6 and its subrequirements. Based upon comments from industry, the SDT revised FAC-011 and FAC-014 and left to the TOP and IRO standards the determination of SOL exceedances using the framework established with requirement R6. Instead, the SDT added a new requirement R7 that required inclusion in the SOL methodology "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur." This addition provides structure around existing TOP and IRO standards which require communication of SOL exceedance information between RCs and TOPs and allows the RC to determine a single method for communication

of SOL exceedances, with a defined timeframes. The new requirement R7 establishes minimum requirements for set of SOL exceedances in regards to communication, but leaves the remaining details to be determined by the RC.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase 2 of this project. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comments and agrees with suggestion. The IROL topic will wait until after these FAC standards are revised.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance. However, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. Due to reasons that we outlined in response to the question 1 (see above) we find it inappropriate to incorporate the definition of SOL Exceedance as a performance criteria in	

Requirement 6 of FAC-011-4 Standard and significantly worse and more risky in comparison with coming up with definition of SOL Exceedance**.**

NV Energy shares the industry concern that the proposed changes to Standards FAC-011-4 and FAC-014-3 would cause the following unintended consequences and repercussion:

- If approved, new versions of the NERC Standards FAC-011-4 and FAC-014-3 **would expose a large number of TOPs and RC to the SIGNIFICANTLY increased compliance risk (direct violation of the FAC-014 R6 in conjunction with FAC-011-4 R6) unless enormous resources and efforts are added within each TOP's/RC's organization.**

- **If the interpretation is correct that TOP/RC would not violate FAC standards in case of exceeding performance criteria as long as they implement their Operating Plan (per TOP-001 R14), our above mentioned concern transforms into another concern about huge administrative, compliance related, burden. Namely, TOP/RC would have to have** (as evidence of compliance), logging and recording documentation that it implemented its Operating Plan in response **to each and every instance when projected post-contingent flow on RTCA exceeds highest emergency rating, even for short time period (such as several minutes).**

- Therefore, due to the absence of time-frame considerations for exceedances of projected post-contingent flows or voltages, the new versions of the NERC Standards FAC-011-4 and FAC-014-3 would cause frequent SOL exceedances (and therefore frequent violations of the new FAC-011 performance criteria) and prohibitively costly and time consuming administrative burden.

- **This definition may decrease reliability as opposed to the SDT's intention of increasing reliability, because of the overwhelming pressure on transmission operators and reliability coordinators to record and communicate frequent SOL exceedances as opposed of being focused on monitoring and implementing control actions to maintain system reliability in real-time.**

- We believe the definition would **delay implementation of the Operating Plan in real-time** due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today.

- We believe that another unintended outcome would be operation **in an unnecessarily conservative state, as TOP would have to operate with higher reliability margin from the highest emergency rating, to ensure that following a forced outage or other system disturbance, that the next execution of real-time contingency analysis would not show any facility beyond its highest emergency thermal rating or emergency voltage rating**

- **The proposed standards would significantly constrain the business in the industry** as conservative limits would **not allow for many of scheduled outages to proceed** without risk of SOL exceedance/performance criteria violation.

We re-iterate our ***recommendation that SDT re-considers adoption of the performance criteria/SOL exceedance per above mentioned suggestions.*** We believe that these modifications would provide the following benefits:

- They are *more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure*
- *They would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance.
- They would provide *comparably reliable operation* of power systems.
- They are *based on physical limitations of various components of transmission facilities*.
- They would *prevent potentially huge increase of cost* of market operations.
- They provide *more clarity and avoid ambiguity and interpretation issues*.

Likes 0	

Dislikes 0	
Response	

The SDT appreciates your comments. Your comments on these impacts were made by many industry participants. As such, the SDT listened and revised the FAC standards. In addition, the SDT is proposing to make changes to the TOP-001 and IRO-008 standards to address the concern you and other industry commenters have raised. Based on the concerns, the SDT revised FAC-011 and made requirement R6 and its subrequirements a framework for use in determining SOL exceedances. The SDT has made revisions in TOP-001 and IRO-008 that when SOL exceedances are determined in those standards, the determination is made using the framework established by FAC-011-4 requirement R6. In addition, recognizing the communication and documentation concerns raised by using the SOL exceedance framework and existing requirements in TOP-001 and IRO-008, the SDT included a new requirement (R7) in FAC-011-4 which required inclusion in the SOL methodology "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur.". This allows the RC and its TOPs to manage communication of the SOL exceedances using a method defined by the RC. In addition, the SDT modified some of the measure language in TOP-001 and IRO-008 such that examples of acceptable documentation have been expanded to demonstrate compliance with those requirements where communication of SOL exceedances is required. Some of those examples in electronic communications, the Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

The SDT goal with these changes was to lessen any administrative burden caused by the revised FAC standards and instead allow system operators focus on operating the system within these new standards and allow reasonable efforts for compliance documentation.

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	
Document Name	
Comment	

We believe R1 should be the only requirement in FAC-011-4. The SDT can accomplish their goal by having Requirement R1 that requires an entity to cover the performance criteria within a newly created appendix. There are 9 requirements and approximately 34 sub-parts in FAC-0011 that increases compliance risk without commensurate benefits to reliability.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates you offering comments on our efforts. Much of the conversation regarding FAC-011 and its current form has focused on inconsistent application of the standard across industry. Those comments, combined with the fact that the edit you suggest would have to be shown to cause no adverse impact on reliable operation of the system on the reliability standard revision process, make your suggested revision untenable, after SDT review.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	Proposed text for FAC-011-4 R5, R6, and R7.docx
Comment	
a. Stability Limit should be capitalized as it is a defined term b. The wording of FAC-011-4 R5 implies that stability studies are required for OPAs and RTAs. This would be a new requirement and does not correspond with the SDT's intent. We suggest the edits to R5 shown in the attached WORD document to clarify that stability studies are not needed for OPAs and RTAs, but, rather, stability limits derived by other studies need to be respected in OPAs and RTAs. c. Please clarify the need for the word "potential" in R6 as the word is not used in other places, such as the TPL standards, where single contingencies are also referred to without the word "potential." We suggest the following language to R6 and R7. d. The word "potential" is not used elsewhere to modify contingencies, which are, by their nature, "potential." For example, in the TPL standards, single contingencies are referred to without the word "potential." For this reason, AZPS recommends that the SDT clarify the need for inclusion of the word "potential" in R6. If such need is not identified, AZPS suggests the following language to R6 and R7. Further, AZPS	

notes that performance criteria is established in Requirement 6.1 as well as in FAC-014, requirement R6. For this reason, its inclusion in Requirement R6.3 appears redundant. AZPS recommends deletion as set forth below. Finally, AZPS recommends consistency when referring to the operation of the BES within SOLs. For this reason, AZPS recommends replacing "violating" with "exceeding" in Requirement R7. e. The wording of FAC-011-4 R6.1.3 and R6.2.3 seems to imply that dynamic studies are required for OPAs and RTAs. This would be a new requirement and does not correspond with the SDT's intent. AZPS also suggests adding the word "widespread" under R6.1.3 and R6.2.3 to exclude local area instability or instability of a small generator. We suggest the following edits to R6 to clarify that dynamic studies are not needed for OPAs and RTAs, but, rather, stability limits derived by other studies need to be respected in OPAs and RTAs. f. As written, FAC-011-4 R6.1.1 and R6.2.1 leaves the burden of proof on the TOP to be able to demonstrate that the operating actions can be taken within the appropriate time of the Facility Rating which is a very difficult and extensive task. g. Regarding R6.2.1, if RTCA shows that emergency ratings are exceeded, there should be a recognized time frame in which to correct the problem prior to it becoming a compliance issue. As written, the proposed definition does not recognize a time-frame associated with exceedances of the facility's highest emergency rating. If not recognized, this could lead to a large volume of inconsequential exceedances such as those less than one minute and have magnitude of less than one percent. h. AZPS suggests R6.1, R6.2, and R6.3 be broken into two separate sub-requirements: one related to Real-time monitoring and Real-time Assessment, and one related to Operational Planning Analysis.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciate the comments you offered on our posting. The SDT did not use the capitalized term Stability Limit in FAC-011 because the SDT did not believe the definition captured what was intended the intended use for stability limits within the revised FAC-011 standard. For example, one drafting team member stated that they used a short circuit calculation to determine if additional conventional generation needed to be committed to allow proper operation of non-conventional generator controls. This "limit" did not fit within any defined limit, including Stability Limit, and as such, the SDT decided to use instead the more flexible "stability limits" term to capture those limits that otherwise would fit in no other category.	

The wording of requirement R5 has been revised and should no longer imply the need for stability studies for OPAs and RTAs. The SDT has revised all of requirement R6 and removed the word “potential”. The SDT has revised requirement R6, and specifically subrequirements R6.1.3 and R6.2.3 and removed the implication that dynamic studies are needed for OPAs and RTAs. The SDT had extensive discussion in regards to the wording in subrequirements R6.1.1 and R6.2.1 with use of emergency limits and any specified time duration of those Emergency Ratings. This is a current issue and not one created by use of the language in this subrequirement. Using this language in the subrequirements, though, does make clear that this issue cannot be ignored by the TOP when using Emergency ratings, which the SDT and many observers felt was appropriate. With regard to your comments on time frames for SOL exceedance correction in subrequirement R6.2.1, the SDT did not feel it as appropriate to include a time frame within the SOL exceedance determination framework within requirement 6. Instead, the SDT create a new requirement 7 which required the SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur.” In addition, subrequirements R7.2 and R7.2.1 state that post-contingency SOL thermal exceedances not mitigated within 30 minutes must be communicated. In this way, no timeframe was created to dictate when an SOL exceedance much be mitigated, but this new requirement does define the maximum amount of time that may be taken to mitigate a post-contingent SOL thermal exceedance before it is communicated per the RC’s SOL methodology and per appropriate TOP and IRO requirements. Finally, with respect to your revision suggestion to subrequirements R6.1, R6.2 and R6.3, the SDT believes that our revisions meet the needs you have described and no longer would benefit from such a revision.

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	

This standard in its current form allows a single entity the ability to dictate operating and effectively planning criteria. PNM believes that the development of the SOL methodology should be a joint effort including RCs, TOPs, and PAs.

PNM believes R2 gives the RC that ability to dictate how an entity uses its own Facility Ratings effectively modifying FAC-008. PNM agrees the requirement does not specifically change, limit, or modify Facility Rating determined by the equipment owner; however, there is no point for an entity to establish a Facility rating that can't be used when operating the system. PNM recommend removal of R2 and revision of FAC-008-3 to address any concerns regarding the coordination of Facility Ratings.

PNM questions the reliability basis of R3.3. PNM believes that there may be reasons to have the UVLS setting higher than the limits for certain critical contingencies. FERC order No. 818 specifies not using UVLS for N-1; however, this requirement doesn't have that qualifier. If the SDT feels this concept should be included in the standard that requirement should move under R4.6 and shall clearly specify that it is only applicable to single contingencies.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments you have offered on our posting. The SDT discussed your first comment at length. During the discussion that it is the RC is the entity with the ultimate authority to operate the system. As such, it can clearly establish the criteria used to determine which system operating limits (SOLs) are used in operations. Similarly, the PC is the entity that has the ultimate authority to plan the system. As such, the RC can develop its SOL methodology on any basis, and is not precluded from discussing any aspect of its SOL methodology with any other entity, including PCs. However, the SDT saw that effort as not mandatory, but elective, on the part of the RC as it develops its SOL methodology.

The SDT appreciates your comment on requirement R2. As we have noted to other similar commenters, the RC needs to determine, among many things, the rating set it needs to operate within its footprint. For example, if the RC determines it needs a 15 minute, a 4 hour and a normal, 24 hour thermal rating for each branch in the network, the asset owner can determine if they wish to provide those ratings or not. The RC cannot dictate a facility owner provide a specific rating, but instead can only use the ratings provided within the rating set it

establishes. The SDT felt this wording of requirement R2 was appropriate given the RC's and asset owners responsibilities. As such, since the RC has the responsibility to respect all limits including thermal, and the SDT believes the RC has the right to determine which ratings it needs to operate, the SDT will not remove requirement R2. With respect to your comment on subrequirement R3.3, the System Voltage Limits are only used for post-contingent conditions for the contingencies identified in subrequirement R5.1, per subrequirement R6.2.2. All of the other contingencies identified in subrequirement R5.2 only has to meet the performance framework described subrequirement 6.3, which does not include System Voltage Limits.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	
Document Name	
Comment	
Entergy supports the comments submitted by MidAmerican Energy Company.	
Likes 0	
Dislikes 0	
Response	
Please see our responses to Mid American comments.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	
The construct of the current active version, FAC-011-3, makes for a lengthy RSAW response with respect to Requirements that lump all SOL types (thermal, voltage, stability) into a single Requirement. The SDT efforts to split these types up into their individual areas, should make	

for a much more consistent, focused & streamlined RSAW, appreciated by both the Applicable Functional Entity, and their incoming audit teams alike.

For the SDT's consideration

In all areas (Standard, Rationale, Mapping, etc.)

- R3.1 "Reliability Coordinators" should be either "Reliability Coordinator" or "Reliability Coordinator's"; (Note: Given that R3 is talking about the RC SOL Methodology, one could argue that the full reference to the RC SOL Methodology again in R3.1 is duplicative, and could be replaced with "Methodology");
- R5: Repetitive language around determining stability limits and performing OPA & RTA could be remedied for greater clarity by splitting into one requirement focused on stability limits and one requirement focused on OPA & RTA. Otherwise, to stick to the same structure you have for R5.1, R5.2 & R5.3 could be merged into one sub-requirement.
- R8: Inconsistency between Standard language. "Reliability Coordinator." vs "Reliability Coordinator(s)."
- M7, M8, M9: Incorrect references to M6, M7 & M8 respectively.

The rationale document for FAC-011-4 has the following typos:

- R3.1 "specificall" should be "specifically"
- R6.1.1 "normal rating" should be capitalized "Normal Rating"
- R8 Rationale discusses R7, when it's referring to R8.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. We will review our use of "Reliability Coordinators" throughout the document accordingly.

The SDT revised requirement R5 and its subrequirements and eliminated duplicative references to OPA & RTA.

The SDT also corrected the noted references in measure M7, M8 and M9 or FAC-011-4.

Finally, we appreciate your review of the rationale document and will attempt to correct the concerns you have noted.

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

No response.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	
Document Name	

Comment

NIPSCO is in MISO and it appears that the prescribed performance criteria here will change the MISO SOL exceedance methodolgy that we presently operate under for TOP-001 R14 and R15. This may be a concern.

We were triple-booked for the related 2015-09 informational webinar. We were hoping to view the streaming replay but never saw it posted. We inquired and were told it would soon be posted but never saw it. Please post promptly next time if possible. Thanks.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Your comments, and those or other MISO members have been noted and resulted in the SDT asking for observer participation from MISO and MISO members. We were pleased at the level of support offered, and the resulting new posting reflects those efforts. In addition, we have noted your comment regarding the posting of the webinar and have noted it to the appropriate NERC staff.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Please see our responses to the comments of the MRO.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA believes Requirement 3.5 should be modified for clarity: change "provide" to "define." *"Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and "define" the method for determining the common System Voltage Limits to be used in Operations."*

BPA believes that in Requirement 4.1.3, the term should remain "angular stability" as this is industry standard. "Unit stability" is not a defined term and is not as understood as angular stability.

BPA recommends consolidating requirements 5.2 and 5.3 and requirements 6.3 and 6.4 to make it so an RC may specify additional single or multiple Contingency events or types of Contingency events for use in determining stability limits and performing OPAs and RTAs. BPA does not support the RC being allowed to specify two additional lists (as allowed by 5.2 and 5.3 when not consolidated) of single or multiple Contingency events or types of Contingency events because BPA believes this could complicate the RC's SOL Methodology without benefiting reliability. If there is a reliability benefit, BPA would like to request the SDT include that in the White Paper.

BPA proposed edits:

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits and performing OPAs and RTAs.

Delete 5.3

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

Delete 6.4

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
The SDT revised subrequirement R3.5 based upon your replacement word suggestion.

The SDT retained "angular stability" in subrequirement R4.1.3.

The SDT recognizes your comment for suggested edits in subrequirements R5.2 and R5.3. Subrequirment R5.3 was removed. Subrequirement R5.2 was revised and simplified as follows:

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

The SDT, based on your comments, those or others, and our discussion, decided to remove the attributions to the contingency's use. It was felt that the RC should have discretion on how to apply these added contingencies, especially based upon SDT discussion which noted examples that already exist of RCs applying unique contingency types beyond single contingent events to subsets of reliability criteria (for example, for establishment of IROLs only).

Subrequirement R6.4 from the second posting has been removed. Revisions to requirement R6 and subrequirement R6.3, based upon comments such as yours, we believe have addressed your concern.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MidAmerican Energy Company (MEC) understands and supports the SDT's efforts to come up with the broad industry consensus with regard to definition of SOL and associated definition of SOL Exceedance. However, we believe that addressing a fundamental concept of SOL Exceedance definition needs to be done within the framework of IRO and TOP standards, where it inherently and logically belongs. Due to reasons that we outlined in response to the question 1 (see above) we find it inappropriate to incorporate the definition of SOL Exceedance as a performance criteria in Requirement 6 of FAC-011-4 Standard and significantly worse and more risky in comparison with coming up with definition of SOL Exceedance.

MidAmerican believes that the proposed changes to Standards FAC-011-4 and FAC-014-3 would cause the following unintended consequences and repercussion:

- If approved, new versions of the NERC Standards FAC-011-4 and FAC-014-3 would expose a large number of TOPs and RC to significant increased compliance risk (direct violation of the FAC-014 R6 in conjunction with FAC-011-4 R6) unless enormous resources and efforts are added within each TOP's/RC's organization.
- If the interpretation is correct that a TOP/RC would not violate FAC standards in case of exceeding performance criteria as long as they implement their Operating Plan (per TOP-001 R14), our above mentioned concern transforms into another concern about huge administrative, compliance related, burden. Namely, TOP/RC would have to have (as evidence of compliance), logging and recording documentation that it implemented its Operating Plan in response to each and every instance when projected post-contingent flow on RTCA exceeds highest emergency rating, even for short time period (such as several minutes).
- Therefore, due to the absence of time-frame considerations for exceedances of projected post-contingent flows or voltages, the new versions of the NERC Standards FAC-011-4 and FAC-014-3 would cause frequent SOL exceedances (and therefore frequent violations of the new FAC-011 performance criteria) and prohibitively costly and time consuming administrative burden.
- This definition may decrease reliability as opposed to the SDT's intention of increasing reliability, because of the overwhelming pressure on transmission operators and reliability coordinators to record and communicate frequent SOL exceedances as opposed of being focused on monitoring and implementing control actions to maintain system reliability in real-time.
- The definition would delay implementation of the Operating Plan in real-time due to logging and documentation requirements, as this functionality is not a built-in feature of many SCADA systems in use today.
- Another unintended outcome would be operation in an unnecessarily conservative state, as TOP would have to operate with higher reliability margin from the highest emergency rating, to ensure that following a forced outage or other system disturbance, that the next execution of real-time contingency analysis would not show any facility beyond its highest emergency thermal rating or emergency voltage rating
- The proposed standards would significantly constrain the business in the industry as conservative limits would not allow for many of scheduled outages to proceed without risk of SOL exceedance/performance criteria violation.

The SDT should reconsider adoption of the performance criteria/SOL exceedance per above mentioned suggestions, which are in accordance with current definition of SOL exceedance that is in effect in MISO Reliability footprint. These modifications would provide the following benefits: • They are *more realistic in recognizing reality of existing transmission infrastructure and human resources allocated to operate such an infrastructure* • *They would provide for significantly less administrative burden* on numerous Industry's entities related to providing evidences of compliance. • They would provide *comparably reliable operation* of power systems. • They are *based on physical limitations of various components of transmission facilities*. • They would *prevent potentially huge increase of cost* of market operations. • They provide *more clarity and avoid ambiguity and interpretation issues*.

Likes 0	
Dislikes 0	

Response
The SDT appreciates the comments of MidAmerican Energy Co. and, more so, its participation in the SDT team's efforts since the second posting. Those efforts have resulted in revisions to FAC-011-4, FAC-014-3, TOP-001 and IRO-008 which we believe address the concerns you raise above, and other commenters have noted. These revisions have been made to accomplish the following: - Have SOL exceedances determined in the appropriate TOP and IRO standards rather than the FAC standards. - The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards

- FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.
- The measures for a few TOP and IRO standards were revised to better describe a more complete set of potential evidence that may be sued to show compliance. In additional, the standard rationales have been revised to explain how this evidence may be used to show compliance with the standards.

We believe these changes, which were developed with the support of and feedback from your company and others from within MISO, should address these commonly held industry concerns.

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	
Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see our responses to the comments of the MRO.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	

Document Name	
Comment	

We offer the following specific comments:

Sub-Requirement R4.1.3:

It is not clear what is meant by "unit" stability. We suggest reverting back to using the current term "angular" stability as it is a term well understood by the industry.

Sub-Requirement R4.3:

A main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Sub-Requirement R4.3 to establish SOLs that impact on the Interconnection:

"Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirements R5.2 and R5.3

Sub-Requirements R5.2 and R5.3 require the RC to identify any additional single or multiple Contingency events. We believe that specifying, at a minimum, which contingencies must be respected (similar to Sub-Requirement R5.1.1. for single Contingencies) would improve reliability. In particular, to the extent there is an alignment in respecting the same set of contingencies and performance criteria for IROLs.

Furthermore, the loss of small or radial portions of the system should be acceptable provided the performance requirements are not violated for the remaining bulk power system.

Sub-Requirement R6.2.2

Sub-Requirement R6.2.2 should include the same wording as sub-requirement 6.1.2:

"Voltages are within normal System Voltage Limits; however, emergency

System Voltage Limits may be used when System adjustments to return

the voltage within its normal System Voltage Limits could be executed

and completed within the specified time duration of those emergency System Voltage Limits."

Sub-Requirements R6.3 and R6.4

For consistency purposes, we recommend that Sub-Requirements R6.3 and R6.4 also require to demonstrate that flow through Facilities are within Normal Ratings, similar to Sub-Requirements 6.1.1 and 6.2.1:

"Flow through Facilities are within Normal Ratings; however, Emergency

Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings."

Sub-Requirements R7.1 and 7.2

Sub-requirements R7.1 and R7.2 require to describe how to identify IROLs, and to identify the criteria for IROLs which is basically the same thing. We recommend merging these sub-requirements into one:

7.1. A description of the criteria to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs) and for developing any associated IROL Tv.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. We note the similarities between your offered comments and those of NPCC. As such, we have supplied essentially the same responses below to those comments also offered by NPCC.

The SDT revised subrequirement R4.1.3 and used "angular stability".

With regard to your comment on subrequirement R4.3, the parent requirement, R4, states that the "Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: . . . " which already makes subrequirement R4.3 subject to the RC's SOL methodology. We believe the suggested text addition is not necessary in R4.3.
With respect to your suggested changes for subrequirements R5.2 and R5.3, the SDT discussed your concern at length. Based on that discussion, and an inability to find industry consensus, and other industry comments, the SDT combined subrequirements R5.2 and R5.3 into one subrequirement, and simplified it.

In addition, your point with regard to small portions of the system is duly noted and reasonable, but the SDT did not find a location within the standards where this seemed a good fit. As such, it was not included in our revised standards.

With respect to your suggested revision for subrequirement R6.2.2, the SDT did not think it appropriate to suggest post-contingent voltages need to be within normal System Voltage Limits. The SDT agreed that emergency System Voltage Limits are appropriate for use in the post-contingent state. The SDT further recognized that emergency System Voltage Limits make take on a variety of forms, with varying potential time applicability, and as such, thought the each TOP / RC would use their emergency System Voltage Limits appropriately as they transitioned the system to a new pre-contingent state to prepare for the next contingency without the need for further language in the standard.

The SDT discussed at length new subrequirements R6.3 and R6.4, including which reliability criteria should be applicable. The SDT could only agree that any contingencies included in the RC's contingency list per subrequirement R5.2 should only have to demonstrate the performance described in subrequirement R6.3. RCs are not precluded from having more prescriptive criteria for any contingency they specify per subrequirement R5.2. In addition, subrequirement R6.2.1 already establishes appropriate thermal performance in the post-contingent state and is not required to be restated in subrequirement R6.4.

The SDT has accepted your suggestion of combining subrequirements R7.1 and R7.2 into a single requirement.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
No	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	

1. R 4.1.3: why SDT used "unit stability" instead of "angular"? We believe it is better to match the language in PRC-26 R1.
2. R.4.7: We would recommend revising the requirement R4.7 to state that the use of UFLS and UVLS is not allowed in the establishment of stability limits for the single contingencies identified in R5.1.1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

We have replaced "unit" with "angular" in subrequirement R4.1.3, as you have suggested.

The SDT recognizes the comment you have offered with regard to subrequirement R4.7. The SDT discussed of UVLS and UFLS at length with regard to stability limit determination. The consensus with regard to UVLS use was that, for typical stability concerns, such as angular stability and transient voltage recovery, UVLS would not typically provide any performance improvement, and actually might exacerbate the stability concern, so UVLS should not be used to determine stability limits. While UVLS would not be used to establish a stability limit, modeling UVLS for potential actuation would be useful to determine what the value of the stability limit should be. With regard to UFLS and stability limits, the group consensus was that if a simulation was indicating UFLS actuation within portions of the interconnected system that was still part of the interconnection and not some small island created due to a contingency or RAS action, then UFLS is not an appropriate relay action to rely upon to "save the system" and establish a stability limit.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	

Document Name	
Comment	

The MRO NSRF does have other comments on FAC-011-4:

- R3.3 should be improved by clarifying what undervoltage load shedding (UVLS) systems are in view (i.e. owned by the Transmission Owner, the Distribution Provider, end-use customer). It would seem that R3.3 should not be limited by UVLS relay settings implemented by a distribution utility or an end-use customer. A suggested edit is to clarify these are BES systems as follows: *"in-service BES relay settings for undervoltage load shedding…"*.
- Similar to comments provided in question #1 related to R6.5, Requirement R4.7 should be modified to remove the restriction on using UVLS Programs when setting stability limits. It is generally accurate to state that UFLS should not be relied upon to maintain stability, although the SDT needs to recognize that UFLS may be a necessary component to maintain stability of a portion of a system deliberately islanded by a Remedial Action Scheme. As such, R4.7 should be modified to read, *"State that the use of underfrequency load shedding (UFLS) programs are not allowed in the establishment of stability limits except in specific, documented circumstances (e.g., Remedial Action Schemes)."*

We also support the recently developed SAR, submitted as a result of phase 1 of the Standards Efficiency Review project, to retire many non-essential or redundant requirements. To reduce the need for a similar effort in the future, the MRO NSRF requests the SDT to consider if Requirement R8 is sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it's essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators, which should remove the need for R8. If kept, there may be overlapping compliance obligations with two requirements for the same activity.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The SDT agreed with your point on subrequirement R3.3 and included the phrase "in-service BES" to better describe the subject UVLS relays. The SDT recognizes the comment you have offered with regard to subrequirement R4.7. The SDT discussed of UVLS and UFLS at length with regard to stability limit determination. The consensus with regard to UVLS use was that, for typical stability concerns, such as angular stability and transient voltage recovery, UVLS would not typically provide any performance improvement, and actually might exacerbate the stability concern, so UVLS should not be used to determine stability limits. If you would like to discuss the particular technical concerns, please contact the SDT; we would be willing to listen to more details to better understand your concern in this regard

.

With regard to your comment on IRO-010-2 and requirement 8, the SDT reviewed its potential use within the standards considered for the SDT. The SDT has proposed revisions to FAC-011, FAC-014, TOP-001 and IRO-008 where we attempted to specify the minimum data expectations to determine SOL exceedances, and allow that any further RC data needs can indeed be captured per IRO-010 and its requirements.

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	
Document Name	

Comment

R3.1 introduces ambiguity and potential inconsistency by allowing the Reliability Coordinator to decide whether to require that a BES bus/station have an associated System Voltage Limit without also requiring any sort of technical rationale or criteria. If the intent of R3.1 is to address a specific issue, LES recommends the drafting team clarify their intent within the requirement.

R3.2 is confusing and unnecessary with an in-place definition of System Voltage Limit. As written, R3.2 appears to provide two different methods for an entity to determine voltage limits.

R3.3 should state: "Require that **the upper (or higher)** System Voltage Limits…" for improved clarity.

R3.4 should be removed in consideration that the definition of System Voltage Limit already requires a "minimum steady-state voltage limit". Combining the language from the definition and R3.4 would essentially read "Identify the lowest allowable minimum steady-state voltage limit…" LES is concerned that R2 does not provide adequate assurance that the RC will respect the Facility Ratings established by the TO or the TO's FAC-008 methodology. As written, the language is vague and appears to allow the RC to determine the Facility Ratings that a TO must use. Also, based on the NERC definition of Facility Rating, there is a potential conflict between System Voltage Limits and Facility Ratings as both could utilize voltage ratings. These conflicts between FAC-011-4 and FAC-008-3 and the definition of Facility Rating need addressed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We believe your comment regarding subrequirement R3.1 was unique and not commonly held. The subrequirement was worded in that fashion to allow flexibility for those who wished to specify System Voltage Limits for every station to do so while allowing other entities which used set of voltage limits for a selected set of system stations for the same purpose. Therefore, we will not choose to act on your suggestion at this time. The definition for System Voltage Limits, which pasted ballot on second posting, is shown below: "The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." The definition for System Voltage Limit does not make reference voltage-based Facility Ratings, and as such, the SDT believes subrequirement R3.2 should be retained. The SDT does not agree with your revision suggestion for subrequirement R3.3. System Voltage Limits were commonly discussed by the SDT as ones that have upper and lower bounds, and with respect to UVLS, or undervoltage load shedding, the low bound, not upper, would be the applicable and pertinent System Voltage Limit per this subrequirement. As a result, while appreciated, your suggested revision is not being used at this time.	

The SDT has considered your suggestion that subrequirement R3.4 be removed. It is true that the definition for System Voltage Limit includes the phrase "minimum steady-state voltage limit", the "lowest allowable" voltage limit identified per subrequirement R3.5 may not be the "minimum steady-state voltage limit . . . that provide(s) acceptable performance". As such, the SDT has elected to retain the subrequirement. Finally, the SDT appreciates your comment on requirement R2. As we have noted to other similar commenters, the RC needs to determine, among many things, the rating set it needs to operate within its footprint. For example, if the RC determines it needs a 15 minute, a 4 hour and a normal, 24 hour thermal rating for each branch in the network, the asset owner can determine if they wish to provide those ratings or not. The RC cannot dictate a facility owner provide a specific rating, but instead can only use the ratings provided within the rating set it establishes. The SDT felt this wording of requirement R2 was appropriate given the RC's and asset owners responsibilities. As such, since the RC has the responsibility to respect all limits including thermal, and the SDT believes the RC has the right to determine which ratings it needs to operate, the SDT will not remove requirement R2.
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment
With respect to R5.4, requiring Reliability Coordinators to identify Contingency events to use in determining stability limits for the Near Term Planning Horizon (FAC-015-1 R4) which also includes 5-year horizon is added burden to both Reliability Coordinators and the Planning Coordinators/Transmission Planners without added benefit. The drafting team should consider limiting this requirement to 0-1 year period which would be the most concerning for the Reliability Coordinators.

Likes 0	
Dislikes 0	

Response
Thank you for your comment.
Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
No further comments	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

It is not clear what other additional single contingency events are there that are not already included in R5.1.1.

Some guidance/criteria in selecting/identifying multiple contingency events (R5.2) for use in OPAs & Real-time Assessments would not only be helpful but ensure that the set of contingencies that meet basic minimum criteria are being evaluated.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. One example of a single contingent event that is not included in the current version of subrequirement R5.1.1 is loss of a single breaker. For certain substation designs, either under all facilities in-service or facility out (breaker out) conditions, the loss of a single breaker could cause a line end open condition and cause a post-contingent high voltage condition. The SDT, in collaboration with the drafting team's observers, agreed to not expand the single event contingency list descried in R5.1.1.

With regard to your comment on guidance / criteria in selecting/identifying multiple contingency events, the SDT discussed this issue at length. While SDT members offered some of their practices with respect to multiple element contingencies they respected in their own footprints, consensus could not be reached beyond the inclusion of subrequirement R5.2 as worded for the second, and soon to come posting, neither of which includes such guidance / criteria.

Jack Stamper - Clark Public Utilities - 3

Answer	
Document Name	

Comment

Just a general comment on the use of the term "owner-provided Facility Ratings" used in FAC-011, FAC-014, and FAC-015. I believe this reference is referring to the FAC-008 Facility Ratings that TOs and GOs are required to determine and make available to various reliability entities. This may or may not be true. If it is true, any ambiguity could be eliminated by changing the reference to "Transmission Owner and Generator Owner provided Facility Ratings determined in accordance with FAC-008."

Please at least address the issue in the response to this comment especially if there is a different owner provided facility rating that these standards are referring to. Thanks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. You are correct in that the phrase quoted – "owner-provided Facility Ratings" – are with respect to those Facility Ratings provided per FAC-008 by Transmission and Generation Owners. The SDT thought the phrase was clear enough, and based upon your comment being the only one to note this specific ambiguity, the SDT has left the phrasing in the interest of brevity in the standard language.	

3. The SDT acknowledges that requirement R6 could alternatively be located within a TOP or IRO standard; however, the Project 2015-09 SAR does not specifically authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Proposed Requirement R6 was created to correspond with FAC-011-4 Requirement R6 in lieu of creating a definition for SOL Exceedance. Do you agree with Requirement R6?

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Subject to previous comments.	
Likes 0	
Dislikes 0	
Response	
Please see responses to previous questions.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

However, we have the same comment as with Question 1:

Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the

requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for commenting. Please see responses to concerns in Q1.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
GTC understands this question to refer to FAC-014, Requirement R6.	
Likes 0	
Dislikes 0	
Response	
That is correct.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	

Comment	
Related to Proposed ***FAC-014-3*** Requirement R6, PJM has no additional comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for clarifying.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Cowlitz PUD is not certain which standard requirement corresponds with Requirement R6 (should not be corresponding to itself), but agrees with detailed discriptions contained in a requirement rather than in a defined term. We affirm Proposed Requirement R6 created to correspond with FAC-011-4 (rather than in a TOP or IRO standard) is preferrable to creating a detailed, and complicated SOL Exceedance NERC Glossary term.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. However, after considering feedback from this posting the FAC-011-4 R6 requirement has been improved and the drafting team is proposing to effectively remove the language from FAC-014-3 R6 previously proposed and add it to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern believes that R6 should be a part of an operating standard in the IRO standard category.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE agrees this information would be better suited in the TOP and IRO standards. The current approach requires understanding of how FAC-011-4 and FAC-014-3 fit together as they both refer to each other. It is confusing that the requirements must be read together, even though they reside in two different standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The wording of FAC-011-4 R6.1.1 and 6.1.2 is unclear. Words appear to be missing in the phrase “may be used when System adjustments to return the voltage…”. Reclamation recommends the SDT review R6.1.1. and R6.1.2 to ensure clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team is unclear about which words you believe to be missing and believes the requirement is clear. The concept is that if the steady-state flow through facilities (or the voltage) exceeds that of normal ratings on the facility, emergency ratings (for those that allow higher flows/voltages than normal ratings) may only be used so long as the time they are valid for is not exceeded. As such, the system adjustments necessary to return flows/voltages to below the normal rating but must be complete before the time the emergency rating is valid for runs out.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
: PacifiCorp agrees with Requirement R6 except for the comments made in question 1.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. They will be addressed in Response to those made in Q1.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP supports, in general, the proposed revisions to FAC-011, we believe additional clarity is needed within 6.1.3 to make it clear these obligations are only in reference to known stability limits and do *not* require TOP-provided, dynamic, real-time stability studies. While there are entities that do perform such real-time stability studies, this requirement should not impose that sort of analysis on *all* TOPs. AEP has chosen to vote negative on this revised standard driven by the current lack of clarity in this regard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has revised the sub requirements in R6 that deal with stability and have tried to remove that text which implies a need to perform real-time stability analysis. It is not the intent of the SDT to require any entity to perform real-time stability analysis as part of their Real Time Assessments.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
NPPD supports the comments submitted by the MRO NSRF.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to the MRO NSRF.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to the MRO NSRF.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF is not clear if the question is addressing FAC-014-3 R6, but we believe it is. Although we understand the SDT's intent of placing R6 in FAC-014-3, it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement. For example, TOP-001-4 requires an RTA to be performed by the Transmission Operator in requirement R13. The Transmission Operator is required to examine both the pre-Contingency and post-Contingency states based on the definition of Real Time Assessment. By creating	

FAC-011-3 R5 and R6, the SDT has adequately covered what Contingencies need to be evaluated to identify or monitor SOLs as part of RTAs and OPAs. Similarly, we believe the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10 and TOP-002-4 R1 adequately address the SDT's concern and language of proposed FAC-014-3 R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The question is addressing FAC-014-3 R6; sorry for the confusion. Although TOP-001-4 R10 does require monitoring for SOL exceedances and R13 does require an RTA to be performed, neither requirement ties both concepts together for determining SOL exceedances. Furthermore, TOP-002-4 R1, IRO-008-2 R1 and R4 do not reference how SOL exceedances should be defined; which is what the drafting team had attempted in proposed FAC-011-4 R6. Therefore, the drafting team believes the existing standards quoted do not sufficiently address the issue of uniformity for proper treatment of SOL exceedances necessary for maintaining BES reliability. While the TOP and IROL standards use “SOL exceedance” numerous times, there is no definition of the term anywhere within the standards. Recognizing this and past comments on the SDT’s prior postings on FAC-011, the proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. As a result, the previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. the SDT is revising FAC-011-4 R6 to allow each RC to define SOL exceedances in their methodology, using as an initial basis the performance criteria in R6. This tact should allow each RC the flexibility needed to account for any unique concerns within its footprint while allowing a more seamless use of SOL exceedances defined by this methodology in the TOP and IRO standards. Furthermore, FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Patti Metro - National Rural Electric Cooperative Association - 3,4	

Answer	No
Document Name	
Comment	
As stated, in Q1 NRECA does not agree with the proposed R6. NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to include a review of the TOP and IRO standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

AECI supports comments provided by NRECA.

As stated, in Q1 NRECA does not agree with the proposed R6. NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to include a review of the TOP and IRO standards.

Likes 0	
Dislikes 0	

Response

. Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards.

FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends that FAC-011-4 R6 (6.3 and 6.4) be consolidated. With this edit (see BPA's response to question 2 above) BPA supports FAC-011-4 R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team agrees that FAC-011-4 R6.3 and R6.4 should be consolidated and R6.3 has been revised accordingly.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to the MRO NSRF.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
Additional, patient efforts by the SDT to develop a flexible definition of SOL exceedance is a superior approach versus a FAC-011 and FAC-014 performance requirement. The language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs. MidAmerican shares the MRO NSRF position regarding FAC-014-3 R6 that *"it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums"*. General principles and good utility practice within the industry is to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint,. Consequently, all arguments presented in answering Questions 1 and 2 would apply and be of a significant concern to the TOPs.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment offered. While the SDT supports your perspective in the value of an explicit SOL exceedance definition, it was apparent from prior postings and comments that the industry as a whole did not. Our latest FAC-011-4 revision, with the proposed R6, is our attempt at providing a minimum set of performance criteria across the industry for establishing SOL exceedances. R6 should be the minimal basis any RC uses to define SOL exceedances within its footprint. Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards. We hope you can understand our rationale and support the proposed FAC-011-4 language in our next posting. For further responses to your comments, please see the response provided to the MRO NSRF.
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to the MRO NSRF.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

NIPSCO feels that R6 belongs in the TOP and IRO standards. We understand the SDT does not currently have access to these standards but that should not mean that this requirement is not placed in the appropriate standard. There will need to be a review of the TOP and IRO standard to place R6 in the appropriate place.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not believe that the added requirements in Requirement R6 nor a definition for SOL Exceedance is necessary. Furthermore, CenterPoint Energy believes the SDT unnecessarily broadened the scope of the language by using the term "SOL	

exceedances" without additional focus on those exceedances that adversely impact the reliability of the BES. CenterPoint Energy recommends that the SDT clarify the intent of Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team feels the treatment of SOL exceedances both lacks uniformity and is not being performed as intended by the current set of standards. Therefore, the drafting team is working to clarify the existing standards by creating a requirement in FAC-011-4, R6, outlining the performance criteria minimum framework that each RC footprint must meet in defining determining SOL exceedances in lieu of a prescribed SOL Exceedance definition. Without proper treatment of all types of SOL exceedances, they may need to adverse system impacts. As such, and to provide clarity across the industry, the drafting team is trying to address them all. The SDT did include in its R6 impact on the "BES"to limit the potential scope of instability, per your comment. The SDT also made many other revisions to R6 to improve its clarity. Please also note that the previously proposed R6 requirement in FAC-014-3 has been removed and has been effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports the comments submitted by MidAmerican Energy Company.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see the response provided to MidAmerican.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
No, AZPS is concerned that as proposed, requirement R6 of FAC-014-3 results in a redundancy that could result in ambiguity and confusion. For this reason, AZPS recommends that "SOL exceedance" be defined in FAC-014-3 R6, or FAC-014-3 R6 refers to FAC-011-4 R6 performance criteria instead of referencing "SOL exceedance."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 with references to the RC's SOL methodology (FAC-011-4) such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. Please note the proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. Also, FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment	
NV Energy shares industry concerns regarding FAC-014-3 R6 that *"it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums"*. Furthermore, general principle and good utility practice within the industry is to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint,. Consequently, all arguments that we presented in answering Questions 1 and 2 would apply (and be of a significant concern) to TOPs. Please see all our comments and arguments above. In conclusion, if additional, patient efforts are done by SDT to formulate broad and flexible definition of SOL exceedance, the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. As it echoes that of MidAmerican Energy Company please see our response to MidAmerican.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
The SDT should consider revising the SAR to include modifications to TOP or IRO standards. The SDT should not go forward with Requirement R6 until they have reviewed TOP or IRO alternatives.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to MRO NSRF	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
The SDT appreciates your comment offered. While the SDT supports your perspective in the value of an explicit SOL exceedance definition, it was apparent from prior postings and comments that the industry as a whole did not. Our latest FAC-011-4 revision, with the proposed R6R6, is our attempt at providing a minimum set of performance framework for determining SOL exceedances as required by the TOP and IRO standards criteria across the industry for establishing SOL exceedances. R6 should be the minimal basis any RC uses to define SOL exceedances within its footprint. We hope you can understand our rationale and support the proposed FAC-011-4 language in our next posting.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment offered. While the SDT supports your perspective in the value of an explicit SOL exceedance definition, it was apparent from prior postings and comments that the industry as a whole did not. Our latest FAC-011-4 revision, with the proposed R6, is our attempt at providing a minimum set of performance criteria across the industry for establishing SOL exceedances. R6 should be the minimal basis any RC uses to define SOL exceedances within its footprint. We hope you can understand our rationale and support the proposed FAC-011-4 language in our next posting.	
Spencer Tacke - Modesto Irrigation District - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
We acknowledge the drafting team's question regarding the substance of R6 for FAC-014-3. We do not have any specific concerns regarding the language used. While we understand that the drafting team is not soliciting comment on where a requirement should reside, we would be remiss not to comment that this requirement is indeed out of place as proposed. The proposed R6 is a Real-time performance requirement surrounded by other requirements pertaining to methodology, and not the execution of said methodology. We understand that the SAR does not allow for an alternative approach at this time, but believe that this may need to be revisited at a later date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to ACES Power Marketing for more details.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
SAR Scope Issue	

The companies believe the proposed revisions to FAC-014-3 R6 are, for all intents and purposes, incorporated into TOP-001 and TOP-002, and, as such, creates a potential conflict with Requirements in TOP-001 and TOP-002.

If that is the case, the proposed FAC-011-3 R6 revisions create a challenge to the SDT by basically requiring revision to TOP-001 and TOP-002 and, as such, the revisions fall outside the scope of the SAR.

Observation: SOL Exceedance Glossary Term

The companies would note, and we are confident the SDT is aware, TOP-001 and TOP-002 could be strengthened by a SOL Exceedance Glossary Term and the proposed R6 revisions do not eliminate the need for a SOL Exceedance Glossary Term.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Regarding your observation, the SDT appreciates your comment offered. While the SDT supports your perspective in the value of an explicit SOL exceedance definition, it was apparent from prior postings and comments that the industry as a whole did not.

Regarding the issue you've identified, the **previously proposed R6 requirement has been removed from FAC-014-3 and effectively added** to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards.

FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	
See comments to question 1. Because the SDT is not authorized to make changes to the TOP or IROs is not sufficient reason to place requirements in standards to which they don't belong. The performance criteria should rightly be debated and crafted in the context of system operations by a SDT with appropriate focus and expertise.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to your comments in question 1. In addition please note the **previously proposed R6 requirement has been removed from FAC-014-3 and effectively added** to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	
Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Do not agree with 6.5, too restrictive. Should be allowed to apply non-consequential load loss.	
Likes 0	
Dislikes 0	
Response	

Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture that "planned manual load shedding", if included in an Operating Plan should be a measure of last resort. With respect to RAS, requirement R4.6 requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations" R4.7 specifically requires however "that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits". The use of UVLS and UFLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	No
Document Name	
Comment	
However, we have the same comment as with Question 1: Throughout the standard development process for the revisions of the IRO/TOP standards the IESO continued to comment on our serious concern over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We recognize that this issue is not within the scope of this project, but is directly related through the methodology that will be used to determine operating limits for these unknown states. In order to better coordinate the development of standards, we recommend that the scope of future NERC projects should better identify relationships between families of standards at the onset, and encourage potential revisions to related requirements.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see the response provided under Q1.

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC is not clear if the question is addressing FAC-014-3 R6, but we believe it is given that the previous question asked for any further comments on FAC-011-4 and the next question asks for any further comments on FAC-014-3.

Although we understand the SDT's intent of placing R6 in FAC-014-3, it is inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement. For example, TOP-001-4 requires an RTA to be performed by the TOP in requirement R13. The TOP is required to examine both the pre-Contingency and post-Contingency states based on the definition of Real Time Assessment. By creating FAC-011-3 R5 and R6, the SDT has adequately covered what Contingencies need to be evaluated to identify or monitor SOLs as part of RTAs and OPAs. Similarly, we believe the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10 and TOP-002-4 R1 adequately address the SDT's concern and language of proposed FAC-014-3 R6.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to MRO NSRF and MidAmerican Energy Company.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	
Comment	
The SDT appreciates your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to ACES Power Marketing.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
The criteria given are not clear as written such that they appear to occur in the Real-time horizon and apply to real-time operations rather than in the Operations Horizon as stated. As a consequence, the criteria do not seem to meet a methodology requirement but an operating one. Specifically, the identification of real-time monitoring and assessment as a demonstration is inappropriate for a FAC methodology requirement and belongs in TOP and IRO standards relating to operations. We believe there should not be an operating requirement in FAC-011 and in our opinion is a poor practice and should be shelved. The Standard "families" set certain expectations and should be respected because to do otherwise will create risks of inconsistency. If the TOP and IRO standards need amending, then amend them!	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Regarding the issue, you've identified, the previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards.

FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

ITC agrees with the MRO NSRF that it is not clear if the question is addressing FAC-014-3 R6, but we believe it is. Although we understand the SDT's intent of placing R6 in FAC-014-3, it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums, including the Standards Efficiency Review project. More importantly, we believe that the existing relevant IRO and TOP standards adequately cover what FAC-014-3 R6 intends to implement.

ITC agrees with MEC that if the SDT can formulate a broad and flexible definition of SOL exceedance, the language of IRO-008-2 R1 and R4 as well as TOP-001-4 R10, R13 and R14 and TOP-002-4 R1 would be sufficient and would adequately address the SDT's concerns and industry's needs.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to MEC which also addresses the MRO NSRF's comments.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Without the option of modifying TOP and IRO standards to accommodate a SOL Exceedence definition, it is reasonable to add the performance criteria to FAC-011-4 R6. However, the language in R6 is unclear. While it is clear in 6.1 that we may exceed the Normal Rating without a contingency if we return to Normal within the Emergency Rating time duration, it is not clear in 6.2 that the system response (or anticipated system response) to a single contingency must be within Emergency Ratings. Similarly for 6.3, it is not clear that the criteria is for the system response to the contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team has revised FAC-011-4 R6.2 and R6.3 for clarity around this matter by effectively stating "System performance" in response to those contingencies must meet those criteria including flows through facilities must be within Emergency ratings. Please note that the previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards.	

The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur". This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
IRC Standards Review Committee understands that the current Standards Authorization Request (SAR) doesn't provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SRC recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional reliability benefit but add additional compliance burden to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015. Since the SDT for this Project recognized that there might be a better placement of the Project Requirements, yet apparently felt that a process to consider addressing Standards other than those in the Project's SAR was not available, NERC should consider a process to allow expediting revised SARs that would enable the SDT to address Standards that were not contemplated in the original SAR, while the Project is ongoing.	

The IRC would also like to note that the Standard Efficiency Review Project has made similar observations with respect to consolidation of or better coordination of standards. We would suggest that the SDT work with NERC Staff to follow the approach and principles of the SER team to ensure those efficiencies are realized on this project.	
Likes 0	
Dislikes 0	
Response	
The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards and to limit unnecessary requirements. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SCE shares the opinion of the MRO NSRF regarding FAC-014-3 R6. Specifically, SCE "agrees with the proposed SOL definition. However, as stated in our (MRO NSRF's) response to question 1, we need additional clarification on the SOL expectation of the SDT." Additionally, SCE believes "it's inappropriate to place an operating requirement within the FAC family of standards and doing so is contrary to the improvements being made to the NERC Reliability Standards via various forums." Finally, SCE believes it is good industry practice to align and coordinate definition of SOL and SOL exceedance/performance criteria between RC and TOP's within the RC's reliability footprint.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The previously proposed R6 requirement has been removed from FAC-014-3 and effectively added to both IRO-008 and TOP-001 such that requirements for when SOL exceedances are determined are in the appropriate TOP and IRO standards rather than the FAC standards. The proposed FAC-011-4 requirement R6 has been revised into a framework to be used when determining SOL exceedances, which only occurs as required in the TOP and IRO standards. FAC-011-4 has a new requirement added (R7) which requires the RC SOL methodology include “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur”. This requirement was added to address the ill-defined SOL exceedance communications included within the TOP and IRO standards.	
Randy MacDonald - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Does planned load shedding include automatic load shedding schemes such as UVLS? Within the operational time frame UVLS should be allowed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting teams assumes your comment pertains to FAC-011-4 R6.5. The drafting team has revised R6.5 to clarify the requirement is specifically to prevent manual load shedding before all other System adjustments have been made. Requirement R6.5 from the second posting, which is now requirement R6.4 in the latest version of FAC-011-4, was not intended to address what mitigation actions are acceptable for inclusion in an Operating Plan, including RAS or other post-contingency mitigation actions (including under voltage relays that are not specifically part of an overall Under Voltage Load Shed (UVLS) scheme). The SDT did capture	

that "planned manual load shedding", if included in an Operating Plan should be a measure of last resort. With respect to RAS, requirement R4.6 requires that the RC document in their SOL methodology the "allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations". R4.7 specifically requires however "that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits". The use of UVLS and UFLS as a safety net and not for performance criteria or in the establishment of a stability limit is consistent with FERC commission comments in FERC Order 818.	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
See comments in response to question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the Q1 comment response.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
See comments in response to question 1.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. Please see the Q1 comment response.

4. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	

Answer	
Document Name	
Comment	
Regarding R6: The requirement does not provide sufficient clarity with regard to how SOL methodology is incorporated into RTA and real-time monitoring. For example is the expectation that the methodology be implemented in both RTA and real-time monitoring, or can the real-time monitoring schemes be used to incorporate some aspects of the methodology where the RTA tool lacks capability.	
Likes 0	
Dislikes 0	
Response	
The SDT has updated the proposed FAC-011-4 R6 to clarify that RC's SOL methodology shall include certain performance framework in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. The SDT has also proposed TOP-001-5 R25 and IRO-008-3 R7 to require both TOP and RC to utilize the RC's SOL methodology in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SCE concurs with the MRO NSRF's overall comments regarding FAC-014-3.	
Likes 0	
Dislikes 0	
Response	

Please see response to the MRO NSRF's comment.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that a cleaner approach would be to utilize a definition of SOL exceedance. It is confusing to have FAC-011 and FAC-014 depend on each other to understand what the RC and TOP should be doing with regards to SOL exceedances.	
Likes 0	
Dislikes 0	
Response	
The SDT has updated the proposed FAC-011-4 R6 to clarify that RC's SOL methodology shall include certain performance framework in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. The SDT has also proposed TOP-001-5 R25 and IRO-008-3 R7 to require both TOP and RC to utilize the RC's SOL methodology in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Under part 1.2, Evidence Retention, Requirements R1 through R8 are referenced. However, there are only six Requirements in the proposed revision. ERCOT suggests aligning the Evidence Retention requirement language with the specific number of Requirements.	

The Violation Severity Levels table provides “the items listed in Requirement 5, Parts 5.1 through 5.6.” However, there are only five parts in Requirement R5. ERCOT suggests aligning the Violation Severity Levels table to the specific number of parts in Requirement R5.	
Likes 0	
Dislikes 0	
Response	
The SDT has updated the Evidence Retention and Violation Security Level.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
ITC agrees with MRO NSRF that in order to reduce the need for a future Standards Efficiency Review effort, ITC requests the SDT to consider if Requirement R3 is unnecessary and sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it’s essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators. Once the data specification is sent to the Transmission Operators in accordance with IRO-010-2 R2, the Transmission Operators must provide its SOLs to the Reliability Coordinator to meet the obligations of IRO-010-2 R3. This should remove the need for the proposed FAC-014-3 Requirement R3. If kept, there may be overlapping compliance obligations with two requirements for the same activity.	
Likes 0	
Dislikes 0	
Response	

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC in accordance with the RC's SOL methodology.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. While IRO-010 and its requirements allow an RC to request SOLs of its TOPs, R3 in FAC-014 sets a common expectation across industry of the minimum actions any TOP can take when supplying SOLs to their RC. It is opinion of the SDT after lengthy review and industry comment that R3 in FAC-014 provides a sound reliability basis that should be expected in any RC footprint which is not found anywhere else in the current set of standards.

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

R5 – This should require providing SOL information to Transmission Planners, not just Planning Coordinators, because there is no requirement for Planning Coordinators to provide this information to Transmission Planners. In addition, in FAC-015-1, Transmission Planners are required to coordinate with the SOLs established by the Reliability Coordinators and Transmission Operators. As such, the Transmission Planners should receive SOL information directly from the Reliability Coordinators and Transmission Operators, rather than second hand information from Planning Coordinators. If the SDT decides to proceed with FAC-015-1 as a standard, FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *"Each Planning Coordinator and each Transmission Planner within . . . "*

Likes 0	
Dislikes 0	

Response

The SDT agrees with the comment. The SDT has made the changes in R5.1 and R5.2

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	
Document Name	
Comment	

Requirement R4:

Similar to our comment on Sub-Requirement 4.3 (FAC-011-4) in Question 2, a main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Requirement R4 to establish SOLs that impact on the Interconnection:

"Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirement R5.2.5

A description of the associated system conditions is normally included in the RC's methodology as part of Requirement R4.4 in FAC-011-4. The sub-requirement R5.2.5 can be removed as it is redundant with Requirement R4.4 in FAC-011-4.

Likes 0	
Dislikes 0	
Response	
The SDT agrees with regards to FAC-014-3 R4. The SDT has modified R4.	

FAC-011-4 R4.4 is a general requirement for each RC to have in its SOL methodology description how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; whereas, FAC-014-3 R5.2.5 is a requirement for RC to communicate the specific system condition associated with each of the stability limit or IROL. For example under FAC-011-4 R4.4 an RC may require studies to be performed for both summer and winter seasons considering peak load condition during summer and high transfer during winter off-peak condition. It is possible that following the study results, an IROL is only established during summer but not during winter. This conclusion needs to be communicated under FAC-014-3 R5.2.5	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO believes that the TPL-001-4 covers SOLs and IROLs in the long-term planning horizon. Therefore MISO agrees that the Planning Coordinator should not be the applicable entity that establishes and communicates SOLs and IROLs. The requirement for the RC to provide the PC the SOL and IROLs should reside in FAC-015-1, not FAC-014. R5 – Share results of Operations assessments with Planning: Operations uses real time assessment to identify operating limits. This information has value for Operations assessment, however the value of identifying and sharing these limits with the Planning Coordinator is anticipated to have minimal value to planning assessments. This is in part due to the variability of the scenarios studied in Operations, and how closely those will align to scenarios studied in the Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
The purpose of FAC-014 is to establish and communicate. The RC is currently have the responsibility to communicate SOL/IROL; and therefore it is left for FAC-014.	

Requirement R5 Part 5.1 requires the RC to provide the PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PCs and TPs the relevant information necessary for its assessments. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs and TPs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle. In addition, it requires the RC to provide the impacted PCs the system conditions associated with the Stability Limit or IROL, for example: “summer peak”, “winter peak”, “high import” and etc.

Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	

Cowlitz PUD agrees that the establishment of SOLs and IROLs should be consistent for both operational and planning aspects of the BES. Having a single source for SOL Methodology from the Reliability Coordinator, implementation of the SOL Methodology by the Transmission Operator, and requiring the Planning Coordinator and Transmission Planner to coordinate the Planning Assessments with SOLs and IROLs provided by the Reliability Coordinator will improve Reliability. However, Cowlitz PUD cautions that IROLs should be carefully identified such that local isolated limitations remain as SOLs.

Likes 0	
Dislikes 0	

Response

The SDT will address IROL in phase II of this project following direction and guidance from the MEITF

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	
Document Name	
Comment	

The companies suggest FAC-014 would be strengthened if it better aligned or explicitly addressed the following precepts:

The RC is in the best position to establish guidelines or criteria for determining System voltage limit.

The companies recognize each entities' system is unique in design, complexity, footprint, and Facilities, as is the RC's. To address the differences between systems across the BES, the companies suggest BES reliability will be strengthened by considering the uniqueness of these systems and letting the RC set guidelines or criteria for determining System voltage limits.

The TOP is in the best position to determine limits and avoid conflicts with Facility Ratings.

The revised proposed Glossary Term, while establishing boundaries, may create circumstances that add complexity to determining Facility Ratings, System Voltage Limits, and stability limits. Generally, adding complexity to Standards adds opportunity for undesired results in operating the BES.

To simplify the determination of System Voltage Limits and stability limits, the companies suggest that the TOP determine these values to ensure they do not conflict with Facility Ratings.

Likes 0	
Dislikes 0	
Response	

The SDT believes that the TOP is the best position to establish SOL in accordance with the RC SOL methodology including System voltage limit. FAC-011 R3.2 does requires that System Voltage Limits respect voltage-based Facility Ratings. In addition, the SDT believes that TOP is also the best entity to establish stability limit when it only impacts one TOP. These limits could exist at the same time and all three limits are considered SOL that should be respected at all times.

No changes made in the proposed FAC-014 standards

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase II of this project. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.

Likes 0	
Dislikes 0	

Response

The SDT will address IROL in phase II of this project following direction and guidance from the MEITF.

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	
Document Name	

Comment

The sub-Requirements of R5.2 are a list of specific criteria with the exception of the newly added 5.2.5. Sub-part 5.2.5 is unnecessary and is too general of a statement and could include a variety of system conditions. It is unclear what the SDT is trying to accomplish with 5.2.5. Further in Requirement R6, OPAs and RTAs are listed as acronyms and have not been previously defined in the standard. This issue should also be addressed.	
Likes 0	
Dislikes 0	
Response	
The SDT has also clarified FAC-014-3 R5.2.5 to better describe the intent and how it complement FAC-011-4 R4.4. FAC-011-4 R4.4 is a general requirement for each RC to have in its SOL methodology description how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; whereas, FAC-014-3 R5.2.5 is a requirement for RC to communicate the specific system condition associated with each of the stability limit or IROL. For example under FAC-011-4 R4.4 an RC may require studies to be performed for both summer and winter seasons considering peak load condition during summer and high transfer during winter off-peak condition. It is possible that following the study results, an IROL is only established during summer but not during winter. This conclusion needs to be communicated under FAC-014-3 R5.2.5 With regards to R6, the SDT has updated the proposed FAC-011-4 R6 to clarify that RC's SOL methodology shall include certain performance framework in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. The SDT has also proposed TOP-001-5 R25 and IRO-008-3 R7 to require both TOP and RC to utilize the RC's SOL methodology in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	

Comment	
R4 in its current form gives the RC the ability to establish stability limits when the limit impacts more than one TOP. PNM proposes the following language for R4: Each Reliability Coordinator, in conjunction with the impacted Transmission Operations, shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operators in its Reliability Coordinator Area in accordance with its SOL methodology.	
Likes 0	
Dislikes 0	
Response	
Similar to R1, RC has the authority to establish limits when it impacts wide area. In R4, the RC can establish stability limit when it impacts more than one TOP or when it impacts other RC. In Requirement R5.3-R5.5, the RC is required to provide all necessary information to impacted TOP so that TOP will have the ability to review RC's determination of SOL	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	

Answer	
Document Name	
Comment	
Entergy supports the comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to the MRO NSRF's comment	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	
For the SDT's consideration R5.2.2: The language for the requirement & rationale have two different versions. The requirement appears to be missing the language "critical to the derivation of the". Rationale for R6, inconsistent with R1-R5, leverages an informal interpretation of the R6 standard language.	
Likes 0	
Dislikes 0	
Response	
The SDT has updated the FAC-014-3 R5.2.2 and has also updated the rationale to match the standard language.	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to the MRO NSRF's comment	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	

Answer	
Document Name	
Comment	
In R6 what is the definition of "performance criteria"? NIPSCO believes that "performance criteria" is used in R3 in the establishment of SOLs. It is not something separate from that process. R3 states that the TOP supplies SOLs to the RC according to the RC's SOL Methodology. R6 implies that "performance criteria" is in addition to what is used to establish SOLs. NIPSCO believes that "performance criteria specified in the Reliability Coordinator's SOL Methodology" should be replaced with "SOLs established as part of R3".	
Likes 0	
Dislikes 0	
Response	
The SDT has updated the proposed FAC-011-4 R6 to clarify that RC's SOL methodology shall include certain performance framework in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. The SDT has also proposed TOP-001-5 R25 and IRO-008-3 R7 to require both TOP and RC to utilize the RC's SOL methodology in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	
Document Name	
Comment	
OKGE supports the comments provided by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to the MRO NSRF's comment	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
MEC supports the MRO NSRF overall comments regarding FAC-014-3.	
Likes 0	
Dislikes 0	
Response	

Please see response to the MRO NSRF's comment

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

Requirement R4:

Similar to our comment on Sub-Requirement 4.3 (FAC-011-4) in Question 2, a main concern is the lack of criteria to define contingencies for the establishment of IROLs. Today, some RCs respect single contingencies, while other respect double contingencies. Given the impact on the Interconnection, it is crucial that criteria for the selection of contingency events is defined and applied consistently in all the RC areas, in order to ensure that all IROLs within a defined scope are detected and properly studied. We recommend that the following wording is added to Requirement R4 to establish SOLs that impact on the Interconnection:

"Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas in accordance with its SOL Methodology."

Sub-Requirement R5.2.5

A description of the associated system conditions is normally included in the RC's methodology as part of Requirement R4.4 in FAC-011-4. The sub-requirement R5.2.5 can be removed as it is redundant with Requirement R4.4 in FAC-011-4.

Likes 0	
Dislikes 0	
Response	

The SDT has revised proposed FAC-011-4 R4 to require RC to establish stability limit in accordance to its SOL methodology, which is required to include identification of contingency events. The FAC-011-4 R5 also has been updated so that each RC identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in OPA and RTA. The SDT has also clarified FAC-014-3 R5.2.5 to better describe the intent and how it complement FAC-011-4 R4.4. FAC-011-4 R4.4 is a general requirement for each RC to have in its SOL methodology description how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; whereas, FAC-014-3 R5.2.5 is a requirement for RC to communicate the specific system condition associated with each of the stability limit or IROL. For example under FAC-011-4 R4.4 an RC may require studies to be performed for both summer and winter seasons considering peak load condition during summer and high transfer during winter off-peak condition. It is possible that following the study results, an IROL is only established during summer but not during winter. This conclusion needs to be communicated under FAC-014-3 R5.2.5	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments provided by NRECA. Appears that the drafting team meant to include a specific question on the revisions to FAC-014-03 prior asking for comments on the standard that were not already provided. NRECA believes the format of R5 and sub-requirement 5.2 is cumbersome and suggest the following "bolded" modifications for consideration to provide clarity. 5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, shall provide the following information for each	

established stability limit and each established IROL at least once every twelve calendar months: 5.2.1 The value of the stability limit or IROL; 5.2.2 Identification of the Facilities that are included in the derivation to determine the stability limit or IROL; 5.2.3 The associated IROL Tv for any IROL; 5.2.4 The associated Contingency(ies); 5.2.5 A description of the associated system conditions that impacted the determination of the stability limit or IROL; and 5.2.6 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).	
Likes 0	
Dislikes 0	
Response	

The intent for R5 is to require the RC to provide various data to the various entities based on impacts and needs:

- R5.1 require each RC to provide SOLs to each PC and TP.
- R5.2 requires each RC to provide more information, as specified under sub-bullet 5.2.1-5.2.6, to impacted PC and impacted TP
- R5.3 requires each RC to provide information to impacted TOP
- R5.4 requires each RC to provide information to impacted TOP
- R5.5 requires each RC to provide information to requesting TOP

The SDT has also clarified FAC-014-3 R5.2.5 to better describe the intent and how it complement FAC-011-4 R4.4.

FAC-011-4 R4.4 is a general requirement for each RC to have in its SOL methodology description how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; whereas, FAC-014-3 R5.2.5 is a requirement for RC to communicate the specific system condition associated with each of the stability limit or IROL.

For example under FAC-011-4 R4.4 an RC may require studies to be performed for both summer and winter seasons considering peak load condition during summer and high transfer during winter off-peak condition. It is possible that following the study results, an IROL is only established during summer but not during winter. This conclusion needs to be communicated under FAC-014-3 R5.2.5

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	
Document Name	
Comment	

Appears that the drafting team meant to include a specific question on the revisions to FAC-014-03 prior asking for comments on the standard that were not already provided.

NRECA believes the format of R5 and sub-requirement 5.2 is cumbersome and suggest the following **"bolded"** modifications for consideration to provide clarity.

5.2 Each impacted Planning Coordinator within its Reliability Coordinator Area, **shall provide** the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are **included in the derivation** to determine the stability limit or IROL;

5.2.3 The associated IROL Tv for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions that **impacted the determination of the stability limit or IROL;** and

5.2.6 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Likes 0	
Dislikes 0	
Response	

The intent for R5 is to require the RC to provide various data to the various entities based on impacts and needs:

- R5.1 require each RC to provide SOLs to each PC and TP.
- R5.2 requires each RC to provide more information, as specified under sub-bullet 5.2.1-5.2.6, to impacted PC and impacted TP
- R5.3 requires each RC to provide information to impacted TOP
- R5.4 requires each RC to provide information to impacted TOP
- R5.5 requires each RC to provide information to requesting TOP

The SDT has also clarified FAC-014-3 R5.2.5 to better describe the intent and how it complement FAC-011-4 R4.4.

FAC-011-4 R4.4 is a general requirement for each RC to have in its SOL methodology description how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; whereas, FAC-014-3 R5.2.5 is a requirement for RC to communicate the specific system condition associated with each of the stability limit or IROL.

For example under FAC-011-4 R4.4 an RC may require studies to be performed for both summer and winter seasons considering peak load condition during summer and high transfer during winter off-peak condition. It is possible that following the study results, an IROL is only established during summer but not during winter. This conclusion needs to be communicated under FAC-014-3 R5.2.5

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

To reduce the need for a future Standards Efficiency Review effort, the MRO NSRF requests the SDT to consider if Requirement R3 is unnecessary and sufficiently covered with the IRO-010-2 Requirements. In accordance with IRO-010-2 R1 the Reliability Coordinator can specify any information it needs to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The primary purpose of these activities is to identify SOL exceedances. Therefore, it's essential that the Reliability Coordinator would include in its data specifications SOLs from all Transmission Operators. Once the data specification is sent to the Transmission Operators in accordance with IRO-010-2 R2, the Transmission Operators must provide its SOLs to the Reliability Coordinator to meet the obligations of IRO-010-2 R3.

This should remove the need for the proposed FAC-014-3 Requirement R3. If kept, there may be overlapping compliance obligations with two requirements for the same activity. If the SDT decides to proceed with FAC-015-1; then R1, R2, and R3 obligate each Planning Coordinator and each Transmission Planner to use Facility Ratings that are equally limiting or more limiting than those used by the Reliability Coordinator in its Operations Planning Horizon SOLs. Therefore, FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *"Each Planning Coordinator and each Transmission Planner within . . ."* R5 – should require providing SOL information to Transmission Planners, not just Planning Coordinators, and not rely on Planning Coordinators to provide them to applicable Transmission Planners, especially since there is not a requirement for Planning Coordinators to do so. However, in FAC-015-1 Transmission Planners are required to coordinate with the Reliability Coordinators and Transmission Operators SOLs. Our preference is for the Transmission Planners to get the SOL information directly from the Reliability Coordinators and Transmission Operators, rather than second hand information from Planning Coordinators.	
Likes 0	
Dislikes 0	
Response	
Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC in accordance with the RC's SOL methodology. The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. While IRO-010 and its requirements allow an RC to request SOLs of its TOPs, R3 in FAC-014 sets a common expectation across industry of the minimum actions any TOP can take when supplying SOLs to their RC. It is opinion of the SDT after lengthy review and industry comment that R3 in FAC-014 provides a sound reliability basis that should be expected in any RC footprint which is not found anywhere else in the current set of standards. With regards to FAC-014-3 Part 5.1 and 5.2, the SDT has made modification in R5.1 and R5.2	
Thomas Foltz - AEP - 5	
Answer	
Document Name	

Comment	
AEP believes much of the proposed changes would be beneficial and provide clarity, but would like to provide feedback on some key areas: While AEP has no objections to the proposed changes to R6, and while acknowledging that no changes were proposed to R2, we still would like to again express our concern how the lack clarity in FAC-011 R6.1.3 potentially impacts these requirements in FAC-014. Once again, clarity is needed in FAC-011 to make it clear these obligations are only in reference to known stability limits and do *not* require TOP-provided, dynamic, real-time stability studies as part of OPAs, RTAs, and Real-time Monitoring. AEP has chosen to vote negative on this revised standard driven by the current lack of clarity in this regard. The text “in accordance with” is subjective, and could be interpreted inconsistently across RE footprints as well as within RE footprints. For example, would the language from FAC-015-1 “equally limiting or more limiting than” be considered “in accordance with?” AEP does not object to R1 as proposed, we believe that Transmission Operators should be afforded opportunity to provide input into the process, even if not specifically designated within the standard.	
Likes 0	
Dislikes 0	
Response	
With regards to R6: The SDT has updated the proposed FAC-011-4 R6 to clarify that RC’s SOL methodology shall include certain performance framework in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. The SDT also added a footnote that states “Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques” The SDT has also proposed TOP-001-5 R25 and IRO-008-3 R7 to require both TOP and RC to utilize the RC’s SOL methodology in determining SOL exceedance when performing Real-time monitoring, RTA, and OPA. With regards to the utilization of the phrase “In accordance with”: The SDT believes that the phrase “in accordance with” is commonly used in the approved NERC Reliability Standard	

With regards to R1: The SDT believes that in both R1 and R4, RC has the authority to establish limits when it impacts wide area. In Requirement R5.3-R5.5, the RC is required to provide all necessary information to impacted TOP so that TOP will have the ability to review RC's determination of SOL

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

5. The original posting of FAC-015-1 included six requirements. Industry comments to this original version indicated significant concerns. In response to these concerns, the SDT attempted to streamline and clarify the intended interactions between relevant functional entities and to consolidate the standard into fewer requirements. To achieve this the SDT:

- **Consolidated Requirements R1 – R5 in the original posting into three (R1 – R3) requirements,**
- **Clarified the roles of the Planning Coordinator and Transmission Planner in Requirements R1 – R3, and**
- **Clarified that Facility Ratings are "owner-provided" in Requirement R1.**

The SDT acknowledges that some of the requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc.; however, the Project 2015-09 SAR does not currently authorize the SDT to modify those standards. The SDT is seeking feedback specific to the content of the requirement not where it should reside. Do you support the revised FAC-015-1? Please provide any other comments regarding FAC-015-1.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

FAC-015-1 R4 should more specifically state that each Planning Coordinator and Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Operational Planning Analysis or a Transfer Capability assessment in the Operations Horizon to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generation Owner. The current draft wording may be interpreted as requiring the Planning Coordinator and Transmission Planner to coordinate with the Reliability Coordinator for results of 5-year planning assessment, which is not only burdensome to TP/PC but also non-beneficial to the RC where RC focus is on 0-1 year horizon. As an additional comment, any new requirements put on a Near-Term Transmission Planning Horizon assessment or Transfer Capability assessment in the Planning Horizon would more appropriately reside in the respective Standards for those assessments, TPL-001 and MOD-001, not the new FAC-015-1.

Likes 0	

Dislikes 0	
Response	
The SDT appreciates the comments. It would not be correct to refer to operational analysis performed by planning entities as this is not consistent with the requirements of these entities per the NERC Functional Model. Further, the language posted only requires levels of coordination of performance criteria and not the actual assessment. The SDT has made further changes to withdraw FAC-015 and consolidate the intent of the previous 4 requirements into 3 requirements in a modified version of FAC-014	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
NPPD supports the comments submitted by the MRO NSRF. In addition, NPPD recommends deleting the sub-bullets under FAC-015-1 R2 and R3. Less limiting performance criteria should not be an option.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. See response to MRO comment. There are viable instances where planning entities may use less limiting criteria as documented in the posted rationale for this standard. Further, the standard requires a documented technical rationale from planners for these instances. It is the opinion of the SDT that not allowing these exceptions would not be consistent with the NERC Functional Model in that the RC does not have authority over planning entities.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

The MRO NSRF understands the SDT isn't requesting industry input on the location of the requirements. However, to reduce the need for a future Standards Efficiency Review effort, the MRO NSRF requests the SDT to consider if the proposed FAC-015-1 altogether is needed or if its purpose can be fulfilled with existing standards and/or compliance monitoring processes as described below.

The Data Reporting Requirements in Attachment 1 of MOD-032-1 contains a tabular listing of *"information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon"*. It's also stated in the paragraph above the table *"A Planning Coordinator may specify additional information that includes specific information required for each item in the table below"*. Item 4c in the table is *ratings (normal and emergency)**. The asterisk refers to a note that states *"(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*. It appears these statements along with Requirement R1 of TPL-001-4 establish a compliance expectation for models to *"represent projected System conditions"*, which should include the most limiting Facility Ratings applicable to the modeling scenario. Additionally, if Planning Coordinators, Transmission Planners, Transmission Operators and Reliability Coordinators are not all using the same set of Facility Ratings provided by the Transmission Owner in accordance with FAC-008 R8, then that inaccuracy can be addressed via compliance monitoring for FAC-014, TPL-001 and various IRO/TOP requirements. During its webinar regarding Project 2015-09, the SDT indicated that it would be a very rare occurrence where a Reliability Coordinator would have a more limiting rating than those already provided by Transmission Owners and available to Planning Coordinators and Transmission Planners. Therefore, where is the reliability gap that necessitates creation of Requirement R1 in FAC-015-1?

In a similar manner, if the compliance expectation in Requirements R5 and R6 of TPL-001-4 is for the Transmission Planner and Planning Coordinator to demonstrate a technically sound rationale for voltage and stability criteria applicable to the modeling scenario, then where is the reliability gap that necessitates creation of Requirements R2 and R3 in FAC-015-1?

To ensure relevant entities are considering the information described in FAC-015-1 Requirement R4, it could be added as sub-requirement in FAC-011-4 Requirement R4. To ensure those entities can get the information, it could be requested from the Planning Coordinator and Transmission Planner in accordance with TPL-001-4 Requirement R8. Therefore, is there a need for Requirement R4 in FAC-015-1?

Another consideration in lieu of the new FAC-015-1 standard is to develop compliance guidance, which can improve the industry's understanding of the importance and value in a consistent approach to aligning planning and operational limits.

However, If the SDT decides to proceed with FAC-015, then the MRO NSRF provides the following suggestions for improvement.

Since the FAC-015-1 R1, R2, and R3 obligate each Planning Coordinator and each Transmission Planner to develop SOLs that are equally limiting or more limiting than the Operations Planning Horizon SOLs, then FAC-014-3 Part 5.1 and Part 5.2 should be reworded to *"Each Planning Coordinator and each Transmission Planner within . . . "*

The FAC-015-1 title does not match its stated purpose. We suggest "Coordination of System Planning Criteria and Methodologies with Reliability Coordinator SOL Methodology. The stated purpose of FAC-015-1 is to ensure that Facility Ratings, voltage limits, and stability criteria are coordinated with the Reliability Coordinator's SOL methodology, but R4 is calls for providing selected Planning Assessment and Transfer Capability assessment results to Reliability Coordinators and Transmission Operators. We agree with obligating Planning Coordinators and Transmission Planners to communicate selected assessment results information with Reliability Coordinators and Transmission Operators, but propose that the obligations be added to the respective FAC-013 and TPL-001 standards, not FAC-015-1.

We believe that purpose of FAC-015 would be better fulfilled if it required Planning Coordinators and Transmission Planners to provide their planning horizon Facility Ratings, voltage limits, stability criteria, and methodologies (i.e. TPL-001-4 R5 and R6) to their applicable Reliability Coordinators. This would allow Reliability Coordinators to know what criteria and methodologies Planning Coordinators and Transmission Planners are using in Planning Assessments and better understand how their SOL Methodology might be adjusted to achieve better coordination with the planning horizon criteria and methodologies.

R1, R2, and R3 – We are skeptical that requiring Planning Coordinator and Transmission Planner system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from the Reliability Coordinator SOL methodologies is an appropriate coordination strategy.

R4 – The requirement calls for the communication of CEII information from Planning Assessments and Transfer Capability assessment to impacted Transmission Owners and Generator Owners. This obligation should not be included until it is verified that compliance with the FERC Standards of Conduct can be guaranteed.

Consider the following ideas for sub-parts of a requirement to communicate selected Planning Assessment and Transfer Capability assessment results.

R4.1 – The MRO NSRF agrees with including the type of identified instability but suggest revising the list of examples to match those listed in FAC-011-4 Part 4.1 *“. . . (e.g. steady state voltage instability, transient overvoltage or undervoltage instability, unacceptable tie-line phase angle instability, generating unit loss of synchronism, unacceptable generating unit phase angle damping).* Steady state voltage instability criteria can be a percentage of margin from the expected voltage collapse point in a P-V analysis. The term *“voltage collapse”* incorrectly implies that all Planning Coordinators and Transmission Planners choose the voltage collapse point in a P-V analysis as their voltage stability limit. FAC-011-4 changed *“angular stability”* to *“unit stability”*. *“Transient voltage dip criteria violation”* is not a type of instability. If *“transient voltage dip criteria”* is to be retained, then it should be included in R4.2, as an example of an *“associated stability criteria”* for voltage instability. *“Angular instability”* is a very broad type of instability. Consider providing the Planning Coordinator and Transmission Planner with more understanding of what types of specific angular instability by mentioning some specific sub-elements of the category like those suggested above.

R4.2 – Consider adding some stability criteria examples for the benefit of Planning Coordinators and Transmission Planners, such as steady state P-V curve criteria, steady state high and low voltage protective relay trip levels, transient voltage dip criteria, transient overvoltage spike criteria, transient high and low voltage protective relay trip levels, generating unit loss of synchronism criteria, generating unit phase angle damping criteria.

R4.3 – The MRO NSRF requests the SDT consider the following suggestions for clarification:

1.

- o Asociated Contingencies and Facilities are two different items and should be two separate sub-sections.
- o The Contingencies used in Planning Assessments and Transfer Capability assessments include contingencies beyond the Contingencies used in Operational Planning Analysis.
- o *“Facilities critical to . . .”* does not have a clear meaning and uses the ‘loaded’ wording of *“critical to”*. Consider wording like, *“The Elements that exceed the system performance criteria”*.

R4.4 – No suggested wording change. However after Planning Coordinators and Transmission Planners describe the studied System conditions, it should explained that the System conditions, which will be used for Operational Planning Analysis, may be considerably different from the studies System conditions (e.g. different known outages, different load forecasts,

interchange with economic transfers, different generation resource dispatches), so the reliability impacts identified in the Operations Planning Horizon may be very different from those based on the Near-Term Planning Horizon System conditions. R4.5 – The automatic controls and expected system operator actions that are expected to address potential instability, Cascading, or uncontrolled separation in the Operations Planning Horizon should be split into two sub-bullets or be split into two separate sub-sections. o A sub-section for automatic control actions could say, “Automatic controls expected to address potential instability, Cascading, or uncontrolled separation available in the Operations Planning Horizon, such as Remedial Action Schemes (RASs), undervoltage load shedding (UVLS), underfrequency load shedding (UFLS). o A sub-section for system operator actions could say, “Operating Procedures expected to address potential instability, Cascading, or uncontrolled. R4.6 – We suggest that the wording be modified slightly to something like “Any Corrective Action Plans intended to mitigate or reduce identified instability, Cascading or uncontrolled separation.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT, through coordination with industry and regulatory stakeholders, made the determination that the requirements in the posted FAC-015 were necessary to accomplish the goal of retiring FAC-010. This determination was made because the original intent of FAC-010 and FAC-011 being a mechanism for planning and operating entities to coordinate SOL-related information was not properly accomplished. Therefore, it was necessary to modify the construct of the SOL standards to ensure planning and operations are adequately coordinating the performance criteria that is used in their respective studies. Wording suggestions are duly noted. The SDT has consolidated the language contained in FAC-015 into a modified FAC-014.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No

Document Name	
Comment	

LES recommends the following changes to the bulleted list in FAC-015-1 R1.

- Bullet #1: Recommend removing the first bullet since it is not an exception to the RC's SOL Methodology.
- Bullet #2: Recommend revising the second bullet as follows to be more general and not associated with variations in ambient temperature assumptions only: "Facility Ratings differences are due to variations in **seasonal assumptions such as in** ambient temperature assumptions".

Additionally, the reference to "Near-Term Transmission Planning Horizon" in R1-R3 should only refer to the Planning Assessment with the Near-Term removed. For example, in R1 the required PC/TP process would likely not specify different Facility Ratings between the Near-Term versus Long-Term planning horizons. Use of the phrase "Near-Term Transmission Planning Horizon" in R4 seems appropriate.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments. Wording suggestions are duly noted. The SDT has consolidated the language contained in FAC-015 into a modified FAC-014.

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	No
Document Name	
Comment	

NRECA agrees with the consolidation of requirements and the other changes in the proposed FAC-015-1.

As stated in Q4, NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to not only include the TOP and IRO standards, but to also expand the review to include TPL and MOD standards.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by NRECA. NRECA agrees with the consolidation of requirements and the other changes in the proposed FAC-015-1. As stated in Q4, NRECA believes that the drafting team is not exercising its due diligence by not considering a revised SAR for this project to not only include the TOP and IRO standards, but to also expand the review to include TPL and MOD standards.	
Likes 0	
Dislikes 0	
Response	
See response to NRECA comment.	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The use of the undefined term 'instability' in R4.4 could lead to inconsistent results and result in additional compliance burdens that add little to no reliability benefit. As used in FAC-011 R6, instability is not limited to the BES or wide area but instead, as currently worded, applies to ANY instability that has ANY impact to any element or facility. R4.4 should be limited to the interconnection or at the very least the wide-area to prevent misunderstanding.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has consolidated the language contained in FAC-015 into a modified FAC-014. The use and scope of instability in the requirement referenced in the comment is consistent with the use of the term in the current IROL definition.	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
See comments under question 6 for additional rationale. BPA would like to see R4 modified to state: R4. Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation *“that adversely impact the reliability of the interconnection or other Reliability Coordinator Area(s)”* identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment	

(Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: [Violation Risk Factor: Medium] [Time Horizon: Longterm Planning]	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Wording suggestions are duly noted. The SDT has consolidated the language contained in FAC-015 into a modified FAC-014. The inclusion of the terminology suggested in the comment has been implemented.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports the MRO NSRF recommendation to SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a "micro-managing" manner. That leads to duplication and difficulties regarding interpretation of requirements.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	

OKGE agrees with the MRO NSRF recommendation to SDT “to consider if the proposed FAC-015-0 altogether is needed or if its purpose can be fulfilled with existing standards and/or compliance monitoring processes”.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy does not believe FAC-015-1 is necessary and asks the SDT to reconsider whether the standard is needed at all. CenterPoint Energy believes any reliability concern regarding the proper use of SOLs is addressed by existing standards such as FAC-008, FAC-014, MOD-032, and TPL-001. Additionally, the proper communication of SOLS is addressed by existing standards such as IRO-010, IRO-014, and TOP-003.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT, through coordination with industry and regulatory stakeholders, made the determination that the requirements in the posted FAC-015 were necessary to accomplish the goal of retiring FAC-010. This determination was made because the original intent of FAC-010 and FAC-011 being a mechanism for planning and operating entities to coordinate SOL-related information was not properly accomplished. Therefore, it was necessary to modify the construct of the SOL standards to ensure planning and operations are adequately coordinating the performance criteria that is used in their respective studies.	

The SDT has abandoned the proposal for FAC-015 as a separate standard and has consolidated the requirements into a modified version of FAC-014.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports the comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
FAC-015-1 R4.1 should be limited to TPL-001-4 P1-P7 events. Regarding FAC-015-1 R4.5, TPL-001-4 requires that studies are run with RAS, and if no instability is found, then no additional stability studies are run to determine if RAS was needed to maintain the stability. Also, when a RAS is established, the reason for establishing the RAS (i.e., to address instability or thermal problems) is known. FAC-015-1 R4.5 as written would require additional studies in order to determine whether the RAS is needed to maintain stability, and there is no justification for this additional work because the information would not provide any value. Further, TPL-001-4 P1-P7 events do not permit the use of Under Voltage Load Shedding and Under Frequency Load Shedding to address instability, cascading, or uncontrolled separation, which is referenced in FAC-015-1 R4.5. For this reason, AZPS recommends that those actions not be included in FAC-015-1 R4.5.	

Each requirement of FAC-015-1 appears to already be included in existing standards, or should be incorporated into existing standards as opposed to creating a new standard. The content of FAC-015-1 R1 should be included in MOD-032. The content of FAC-015-1 R2 and R3 should be included in TPL-001. The Planning Assessment requirements referenced in FAC-015-1 R4 should be incorporated into TPL-001-4, and the Transfer Capability Assessment requirements referenced in FAC-015-1 R4 should be incorporated into FAC-013-3 R5. AZPS urges a change in SAR scope or a new SAR to review all of the affiliated requirements and determine whether there is overlap or potential concern with creating a new standard.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Planning Events is the intended focus of the standard proposal. There is no requirement for additional studies to be performed per FAC-015 as the comment suggests. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards. The SDT has abandoned the proposal for FAC-015 as a separate standard and has consolidated the requirements into a modified version of FAC-014.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
PNM believes that allowing a justified exception will still result in a gap between planning and operations and considers this standard, as written, as an additional administrative burden on the PA without having an impact on reliability. Instead of allowing exceptions, PNM suggest that the RC, TOP, and PA should jointly develop system performance criteria.	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Through substantial discussions with industry and regulatory stakeholders, the SDT did not pursue a generic requirement for the entities to coordinate with each other because of the lack of clarity with such a requirement. Rather, the coordination of planning performance criteria with operating performance criteria was determined to be a much more appropriate method to ensure the desired communication occurred. This change removes some of the reliability gaps in the current version of the standards because it requires enhanced communication practices between planning and operating entities.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy shares the industry recommendation to SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a "micro-managing" manner. That leads to duplication and difficulties regarding interpretation of requirements.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards and to limit unnecessary requirements. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	

The SDT has abandoned the proposal for FAC-015 as a separate standard and has consolidated the requirements into a modified version of FAC-014. There is no intent to "micro-manage" the industry. The intent is to ensure that operational and planning studies are better coordinated through the use of complimentary performance criteria.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
While we agree with consolidating requirements, we disagree with the approach of the SDT to include requirements R1-R3 in FAC-015. The SDT should consider revising the SAR to include modifications to TPL or MOD standards. The SDT should not go forward with FAC-015 until they have reviewed TPL or MOD alternatives.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards. The SDT has abandoned the proposal for FAC-015 as a separate standard and has consolidated the requirements into a modified version of FAC-014.	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	
Comment	

There are duplicate of work between this standard and MOD which creates a confusion.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Facility Rating information is part of the steady state data requirements of MOD-032. This data is provided by the owner for use in planning and, ultimately operational models. The intent is for the ratings that are provided by the owner to be used consistently between planning and operations. For example, an owner may provide several time-limited Emergency Ratings. If the RC only operates to a 30-minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	

Comment	
There are duplicate work between this standard and MOD which creates confusion.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Facility Rating information is part of the steady state data requirements of MOD-032. This data is provided by the owner for use in planning and, ultimately operational models. The intent is for the ratings that are provided by the owner to be used consistently between planning and operations. For example, an owner may provide several time-limited Emergency Ratings. If the RC only operates to a 30-minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) understands that the current Standards Authorization Request (SAR) doesn't provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SSRG recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional reliability benefit but add additional compliance risk to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015. Additionally, the SSRG recommends coordinated efforts with the Standards Efficiency Review (SER) Team to see if those particular standards can be modified in the Phase II of the SER without having to revise the current SAR. The SSRG understands that Phase II of the SER is dedicated to Requirements that could be combined and/or modified. From our perspective, this coordinated effort will provide value and efficiencies to both projects by identifying and removing redundancy issues.	

Finally, the SSRG, while recognizing the IROL is not a part of the current comment period, suggests that during Phase II of the project the drafting team re-evaluate the use of references to Planning Assessments of the Near-Term Transmission Planning Horizon that show results of "instances of instability, Cascading, or uncontrolled separation." The SSRG is concerned that the drafting team may have inadvertently omitted how this reference includes TPL-001-4 Table 1 Extreme Events, as well as Planning Events. The SSRG recommends that the drafting team either clarify that the proposed replacement language for IROLs in associated Reliability Standards, as well as FAC-015-1, is only referring to TPL-001-4 Table 1 Planning Events, or, explicitly direct the planning entities to document those Extreme Events that cause instances of instability, Cascading, or uncontrolled separation if they are not specifically identified in Planning Assessments.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards. The intent of the requirements in the posted FAC-015 is to include planning events only. Additional wording has been added in current versions of the SDT's proposal.	
Spencer Tacke - Modesto Irrigation District - 4	
Answer	No
Document Name	
Comment	
The planning horizon should be allowed to have more limiting element ratings than the operating horizon, for more reasons than the ones stated in R1.	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT agrees and feels the technical rationale referenced in the standard can document these instances.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy is unclear on the expectations listed in the sub-bullets for R1. Can a PC or TP use a less limiting Facility Rating with the justification of one of the sub-bullets, or do all sub-bullets need to be satisfied in order to use a less limiting Facility Rating? The use of the word "or" in the 3rd bullet adds tp the confusion. If the intent is that only one sub-bullet must be satisfied, we suggest the following: *"The process may allow the use of less limiting Facility Ratings due to one of the following:"* Also, the second sub-bullet is not clear on where the ambient temperature assumptions are coming from. Would this be referencing a difference between Planning and Operations?	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The source for the confusion is unclear. The word "or" was included to make clear that all bullets do not need to apply for an instance. Additionally, the technical rationale is at the discretion of the planner and is to be utilized to document any needed exceptions (including bulleted items or any others the planner deems appropriate).	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	No

Document Name	
Comment	
There are duplicate of work between this standard and MOD which creates a confusion.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. Facility Rating information is part of the steady state data requirements of MOD-032. This data is provided by the owner for use in planning and, ultimately operational models. The intent is for the ratings that are provided by the owner to be used consistently between planning and operations. For example, an owner may provide several time-limited Emergency Ratings. If the RC only operates to a 30-minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	No
Document Name	
Comment	
Requirement 1 *The intent of Requirement 1 stated in the Rationale for FAC-015-1 "is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." Requiring the Planning Coordinator to change ratings to what is provided to the Reliability Coordinator is contrary to established NERC criteria.* *The requirement as written would require planning to use different ratings than what is provided for the purposes of planning under MOD-032-1 and FAC-008-3 which is contrary to the stated purpose of the standard. As the Transmission Owners are already obligated to provide*	

planning and operating ratings under FAC-008-3 and MOD-032-1, the burden of establishing a technical justification for potentially different ratings used in planning and operations should be placed upon Functional Entities who own facilities (such as Transmission or Generation).

Requirement 2

The rationale provided for Requirement #2 has strong ties to NERC TPL-001. The intent of this requirement is to try and ensure that Planning is fulfilling its role to determine potential reliability deficiencies of the future planned system and to develop Corrective Action Plans to resolve the reliability concerns. This requirement is viewed as a supplement of TPL-001-4 R5.

The voltage requirements stated in TPL-001-4 R5 essentially state that Planning TPL assessments need to have criteria (and document that criteria) for:

- Acceptable system steady state voltage limits
- Post-contingency voltage deviations
- Transient voltage response

o For this criteria at minimum the criteria need to specific a low voltage level and maximum length of time that the transient voltages may remain below that level.

The idea to implement R2 would be to state our requirements as exactly what is put forward in the RC SOL methodology. In reviewing the criteria for the RC SOL methodology, the above criteria for the TPL standard are all achieved with the exception of post-contingency voltage deviation.

Our recommendation would be that FAC-011-4 R4 list include criteria for post-contingency voltage deviation.

Requirement 3

While the rationale provided for Requirement #3 attempts to have ties to NERC TPL-001, no specific requirement of the TPL standard is identified (like there is in FAC-015-1 R2's rationale).

Requirement 4

The rationale for R4 does not provide justification for the inclusion of Transfer Capability Assessments to be included in this requirement. NERC should clarify as to how referencing to FAC-013 plays a role in the requested communication in FAC-015 R4. Further, if the Transfer Capability Assessment respects known SOLS (R1.2) there would be no reporting in FAC-015 regarding Transfers. Further FAC-015 R4.6 requires discussion of corrective action plans which are not required as part of the Assessment of Transfer Capability.

It seems that their argument for rationalizing this standard is circular to existing standards. For example, the rationale states, "the details required by Requirement R4 will supplement the severe system conditions identified in Requirements R4 Parts 4.4 and 45 of the TPL-001-4". The TPL standard requires that entities evaluate the events that may produce the more severe system impacts. It is unclear about how reporting this information per the FAC-015 standard will improve the TPL assessments. It is also unclear how this information in the near-term planning horizon will benefit the entities to which this information is provided. Instead, when violations are observed in the Planning Horizon, corrective Action Plans should be developed which resolve the violation.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments. Regarding the comment on Facility Ratings: The SDT proposal does not change the requirements for owners to provide Facility Ratings per FAC-008 and does not change the PC and TP responsibilities per MOD-032. The intent is for performance criteria between planning and operations to be better coordinated. For example, an owner may provide several time-limited

Emergency Ratings. If the RC only operates to a 30-minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.	
Laura McLeod - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
Disagree with the RC methodology in FAC-014-3 and therefore by extension disagree with the TP and PC using the proposed RC methodology.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
While we appreciate the constraints the SAR places on the SDT, FMPA cannot support FAC-015-1. FMPA still questions if R1-R3 of the proposed FAC-015-1 is even necessary. From the previous comment period: “We question what the value of R1-R3 is and if the	

requirements are even needed. R1-R3 are really dealing with TPL-001-4 and there shouldn't be three additional requirements in FAC-015-1 to deal with the uncommon occurrence of a PC using less limiting Facility Ratings, System steady-state voltage limits, or stability performance criteria. It certainly shouldn't require a technical justification, it should only require coordination"	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards and to limit unnecessary requirements. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The FAC-015-1 title does not match its stated purpose. We suggest "Coordination of System Planning Criteria and Methodologies with Reliability Coordinator SOL Methodology. The stated purpose of FAC-015-1 is to ensure that Facility Ratings, voltage limits, and stability criteria are coordinated with RC SOL Methodology, but R4 is calls for providing selected Planning Assessment and Transfer Capability assessment results to RCs and TOPs. We agree with obligating PCs and TPs to communicate selected assessment results information with RCs and TOPs, but propose that the obligations be added to the respective FAC-013 and TPL-001 standards, not FAC-015-1. We believe that purpose of FAC-015 would be better fulfilled if it required PCs and TPs to provide their planning horizon Facility Ratings, voltage limits, stability criteria, and methodologies (i.e. TPL-001-4 R5 and R6) to their applicable RCs. This would allow RCs to know what criteria and methodologies PCs and TPs are using in Planning Assessments and better understand how their SOL Methodology might be adjusted to achieve better coordination with the planning horizon criteria and methodologies.	

R1, R2, and R3 – We are skeptical that requiring PC and TP system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from RC SOL Methodologies is an appropriate coordination strategy.

In addition, for R2 and R3, note that edits are needed to these requirements if they will be retained. Specifically, the "stability performance" and "System steady-state voltage" language in each of the sub-bullets of R2 and R3 are reversed (i.e. "stability performance" should appear in R3 and "System stead-state voltage" should appear in R2).

R4 – The requirement calls for the communication of CEII information from Planning Assessments and Transfer Capability assessment to impacted Transmission Owners and Generator Owners. This obligation should not be included until it is verified that compliance with the FERC Standards of Conduct can be guaranteed.

Consider the following ideas for sub-parts of a requirement to communicate selected Planning Assessment and Transfer Capability assessment results.

4.1 We agree with including the type of identified instability but suggest revising the list of examples to match those listed in FAC-011-4 Part 4.1 ". . . (e.g. steady state voltage instability, transient voltage response instability, unit instability, System damping). Steady state voltage instability criteria can be a percentage of margin from the expected voltage collapse point in a P-V analysis. The term "voltage collapse" incorrectly implies that all PCs and TPs choose the voltage collapse point in a P-V analysis as their voltage stability limit. FAC-011-4 changed "angular stability" to "unit stability". "Transient voltage dip criteria violation" is not a type of instability, but rather a reference to a type of criteria, which should be cited in Part 4.2.

4.2 Consider adding some stability criteria examples for the benefit of PCs and TPS, such as steady state P-V curve criteria, steady state high and low voltage protective relay trip levels, transient voltage dip criteria, transient overvoltage spike criteria, transient high and low voltage protective relay trip levels, generating unit loss of synchronism criteria, generating unit phase angle damping criteria.

4.3 Consider the following suggestions:

- Associated Contingencies and Associated Facilities are two different items and should be split into two separate sub-sections.

- The Contingencies used in Planning Assessments and Transfer Capability assessments include contingencies beyond the Contingencies used in Operational Planning Analysis.

- “Facilities critical to . . .” does not have a clear meaning and uses the ‘loaded’ wording of “critical to”. Consider wording like, “The Elements that exceed the system performance criteria”.

4.4 No suggested wording change. However after PCs and TPs describe the studied System conditions, it should explained that the System conditions, which will be used for Operational Planning Analysis, may be considerably different from the studies System conditions (e.g. different known outages, different load forecasts, interchange with economic transfers, different generation resource dispatches), so the reliability impacts identified in the Operations Planning Horizon may be very different from those based on the Near-Term Planning Horizon System conditions.

4.5 The automatic controls and expected system operator actions that are expected to address potential instability, Cascading, or uncontrolled separation in the Operations Planning Horizon should be split into two sub-bullets or be split into two separate sub-sections.

- A sub-section for automatic control actions could say, “Automatic controls expected to address potential instability, Cascading, or uncontrolled separation available in the Operations Planning Horizon, such as Remedial Action Schemes (RASs), undervoltage load shedding (UVLS), underfrequency load shedding (UFLS).

- A sub-section for system operator actions could say, “Operating Procedures expected to address potential instability, Cascading, or uncontrolled.

4.6 We suggest that the wording be modified slightly to something like “Any Corrective Action Plans intended to mitigate or reduce identified instability, Cascading or uncontrolled separation.

Likes 0	
Dislikes 0	

Response

The SDT appreciates the comments. The SDT has consolidated the requirements in the posted FAC-015 into a modified FAC-014. There are several supplemental changes to other Reliability Standards that may address some of the other above comments.

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment	
We agree that transmission owner-provided Facility (thermal) Ratings should be used in R1 and that the ratings of existing facilities should be coordinated between RC, PC, and TP entities to ensure system model accuracy. Thermal ratings of future facilities planned for the near-term planning horizon would not be coordinated with the RC as these facilities do not exist in the operating horizon. As proposed, the use of System Voltage Limits described in R2 and stability performance criteria described in R3 would not require coordination between entities, but would be based on the RC methodology and not on local TO planning criteria, which has been filed with FERC and the States. The use of more stringent limits set by the RC would provide the means to unilaterally drive the planning assessment results developed by the PC and TP and could force significant future system expansion above existing planned levels. In our opinion, the language in R2 and R3 needs to be changed to require a more collaborative use of PC and TP existing planning criteria with the RC methodology.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT understands the issue of planned Facilities and their ratings not being included in operational assumptions. This is obviously an allowable exception to the requirements in the standard as stated in the requirement and associated rationale. TO planning criteria is unclear. The Transmission Owner is not a planning entity in the NERC Functional Model.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP agrees with the clarification of "owner-provided" Facility Ratings and restructuring of the requirements. However, SRP has concerns with the language found in R1, R2 and R3. In each of these requirements, the Transmission Planner or Planning Coordinator may use less limiting criteria, limits or ratings if they provide technical rationale to affected Transmission Planners, Planning Coordinators or Reliability Coordinators. SRP is concerned because there is no requirement for the affected entities to agree with the technical rationale. In addition, technical rationale is not a NERC defined term so SRP is concerned with what will be considered technical rationale and what will not. What happens if there is a disagreement between the Transmission Planner and the affected entity as to the technical rationale that was used?	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The entities the technical rationale is distributed to do not have authority over the planning entities per the NERC Functional Model so it would not be appropriate to allow for an approval of the rationale. The technical rationale does not have to be a NERC defined term and is up to the discretion of the entity creating the document.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC agrees with MEC and the MRO NSRF recommendations to SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as numerous additional requirements within various families of NERC Standards attempt to regulate aspects of the industry in a "micro-managing" manner. That leads to duplication and difficulties regarding interpretation of requirements. The Data Reporting Requirements in Attachment 1 of MOD-032-1 contains a tabular listing of *"information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon"*. It's also stated in the paragraph above the table *"A Planning Coordinator may specify additional information that includes specific*	

information required for each item in the table below". Item 4c in the table is *ratings (normal and emergency)**. The asterisk refers to a note that states *"(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*. It appears these statements along with Requirement R1 of TPL-001-4 establish a compliance expectation for models to *"represent projected System conditions"*, which should include the most limiting Facility Ratings applicable to the modeling scenario. Additionally, if Planning Coordinators, Transmission Planners, Transmission Operators and Reliability Coordinators are not all using the same set of Facility Ratings provided by the Transmission Owner in accordance with FAC-008 R8, then that inaccuracy can be addressed via compliance monitoring for FAC-014, TPL-001 and various IRO/TOP requirements. During its webinar regarding Project 2015-09, the SDT indicated that it would be a very rare occurrence where a Reliability Coordinator would have a more limiting rating than those already provided by Transmission Owners and available to Planning Coordinators and Transmission Planners. Therefore, where is the reliability gap that necessitates creation of Requirement R1 in FAC-015-1?

In a similar manner, if the compliance expectation in Requirements R5 and R6 of TPL-001-4 is for the Transmission Planner and Planning Coordinator to demonstrate a technically sound rationale for voltage and stability criteria applicable to the modeling scenario, then where is the reliability gap that necessitates creation of Requirements R2 and R3 in FAC-015-1?

R1, R2, and R3 – We are skeptical that requiring Planning Coordinators and Transmission Planners system planning criteria and methodologies to be equally limiting or more limiting than Facility Ratings, voltage limits, and stability criteria derived from the Reliability Coordinator SOL methodologies is an appropriate coordination strategy. They also require a documentation burden that may ultimately be eliminated in a later NERC Standards Efficiency Review.

Requirement 4 should not be included in a FAC standard. The TPL standard already provides a provision for anyone with a reliability need to obtain the TPL Assessment. Any of these entities must request the TPL Assessment from the PC or TP and identify the reliability need. They must also demonstrate that they can maintain that the communication of CEII information is not outside the bounds of the FERC Standards of Conduct. R4 provides far too much of an open ended list of information on the transmission system and does not guarantee the required confidentiality.

Finally, ITC, while recognizing the IROL is not a part of the current comment period, suggests that during Phase II of the project the drafting team re-evaluate the use of references to Planning Assessments of the Near Term Transmission Planning Horizon that show results of “instances of instability, Cascading, or uncontrolled separation.” ITC is concerned that the drafting team may have inadvertently omitted how this reference includes TPL-001-4 Table 1 Extreme Events, as well as Planning Events. ITC recommends that the drafting team either clarify that the proposed replacement language for IROLs in associated Reliability Standards, as well as FAC-015-1, is only referring to TPL-001-4 Table 1 Planning Events. If it were to explicitly have the planning entities include and document those Extreme Events that cause instances of instability, Cascading, or uncontrolled separation if they are not specifically identified in Planning Assessments, this list would most likely be extremely long and cause issues for planning entities in their completion of all associated studies.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned with the use of a technical rationale to use less limiting Facility Ratings (R1), less limiting System Voltage Limits (R2), and less limited stability performance criteria (R3). There is nothing that states what should go into the technical rationale, who should determine whether or not the technical rational provides a valid reason for not using the most limiting factor, and what shall occur if the technical rationale is not valid. As written, an entity could put any reason whatsoever for not using the most limiting factor and have no consequence if it is not a valid reason.	

Texas RE strongly recommends there be some sort of criteria for a technical rationale, it go through an approval process, and, if not approved, it be sent back to the entity who submitted the technical rationale. At the very least, the technical rationale should explain how reliability is or is not impacted. Texas RE has the following additional comments regarding Requirement R1: • PCs and TPs should request facility owners to provide ratings based on the ambient temperature assumptions in the Planning Assessments, and for each ambient temperature assumption in the Planning Assessment, the PCs and TPs should not be able to use a rating which is less limiting than the corresponding owner-provided Facility Rating. • Higher Facility Ratings for a planned upgrade or addition should only be allowed to be utilized in studies the year the upgrade or addition is expected to be in service and for following years. Facility Rating increases that are only proposed as part of a Corrective Action Plan should not be used in the analysis performed to determine if the System meets performance requirements in Table 1 of TPL-001-4, but may be used to address deficiencies identified as part of the analysis.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The NERC Functional Model does not indicate operating entities having authority over planning entities. Therefore, the notion of approval is not supported by the NERC Functional Model in the opinion of the SDT.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
IRC Standards Review Committee understands that the current Standards Authorization Request (SAR) doesn't provide the authority to revise the TPL, MOD, etc. standards that have a potential affiliation with FAC-015. Notwithstanding, the SRC recommends that the drafting team consider that FAC-015 data requirements are redundant with other families of standards and, therefore, provide no additional	

reliability benefit but add additional compliance burden to responsible entities. For example, MOD-32-1 and TPL-001-4 Requirements both require data provisions that overlap with FAC-015. Since the SDT for this Project recognized that there might be a better placement of the Project Requirements, yet apparently felt that a process to consider addressing Standards other than those in the Project's SAR was not available, NERC should consider a process to allow expediting revised SARs that would enable the SDT to address Standards that were not contemplated in the original SAR, while the Project is ongoing. The IRC would also like to note that the Standard Efficiency Review Project has made similar observations with respect to consolidation of or better coordination of standards. We would suggest that the SDT work with NERC Staff to follow the approach and principles of the SER team to ensure those efficiencies are realized on this project.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards and to limit unnecessary requirements. Ultimately, through exhaustive discussions/debates with industry and regulatory stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SCE agrees with the MRO NSRF (and MidAmerican) recommendation for the SDT "to consider if the proposed FAC-015-0 altogether is needed". The general feeling within numerous industry's entities is that there is a risk of "over-regulation" as several NERC Standards attempt to regulate aspects of the industry in a "micro-managing," or duplicative manner.	
Likes 0	
Dislikes 0	
Response	
See response to MRO comment.	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
FAC-015 creates a sort of double jeopardy for the Transmission Planner by placing the requirement of establishing a process on top of the requirements set out in FAC-001, FAC-007, FAC-011, FAC-014, MOD-032 and MOD-033 to establish and communicate the limits and should not be applicable to entities that already have the requirement to produce and use this data in analysis required by other NERC Reliability Requirements such at TPL-001.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. It is unclear how FAC-001 and MOD-033 is applicable. FAC-007 is not subject to current or future enforcement. FAC-011 applies to the RC.	

FAC-014 is being coordinated with the changes to FAC-010, FAC-011, and FAC-015. The updated plan is to consolidate the requirements in the posted FAC-015 into a modified FAC-014.

Regarding the MOD-032 comment: The SDT proposal does not change the requirements for owners to provide Facility Ratings per FAC-008 and does not change the PC and TP responsibilities per MOD-032. The intent is for performance criteria between planning and operations to be better coordinated. For example, an owner may provide several time-limited Emergency Ratings. If the RC only operates to a 30-minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

The purpose of the FAC-015 standard is to ensure the Facility Ratings, steady-state voltage limits, and stability criteria used in the Planning Assessments are coordinated with the RC's SOL Methodology.

Requirement R4 in FAC-015-1 requires Transmission Planner to communicate its Stability Assessment results to the impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. We agree that Transmission Planner should communicate their Stability Assessment results to impacted entities, but we believe that this requirement belongs to TPL-001 standard and should not be a part of FAC-015 standard.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments. The SDT considered and explored all avenues to place requirements in the correct families of Reliability Standards and to limit unnecessary requirements. Ultimately, through exhaustive discussions/debates with industry and regulatory

stakeholders, the decision was made to retain the notion of coordination of SOL-related performance criteria between planning and operating entities in the FAC family of Reliability Standards.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
FAC-015 creates a sort of double jeopardy for the Transmission Planner by placing the requirement of establishing a process on top of the requirements set out in FAC-001, FAC-007, FAC-011, FAC-014, MOD-032 and MOD-033 to establish and communicate the limits and should not be applicable to entities that already have the requirement to produce and use this data in analysis required by other NERC Reliability Requirements such at TPL-001.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. It is unclear how FAC-001 and MOD-033 is applicable. FAC-007 is not subject to current or future enforcement. FAC-011 applies to the RC. FAC-014 is being coordinated with the changes to FAC-010, FAC-011, and FAC-015. The updated plan is to consolidate the requirements in the posted FAC-015 into a modified FAC-014. Regarding the MOD-032 comment: The SDT proposal does not change the requirements for owners to provide Facility Ratings per FAC-008 and does not change the PC and TP responsibilities per MOD-032. The intent is for performance criteria between planning and operations to be better coordinated. For example, an owner may provide several time-limited Emergency Ratings. If the RC only operates to a 30-	

minute Emergency rating, planning should not plan the system to a 15-minute Emergency Rating. There is no current provision for this instance in the MOD standards.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SME: The standard is much improved from the previous draft. No comments on the content.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Correction: in both first and second bullet points of requirement R3, the “steady-state voltage limits” should be corrected as “stability limit”.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
GTC is in agreement with the SDT's proposed FAC-015-1. The coordination of limits between planning and operations is an improvement over the current construct of having separate SOL methodologies for the planning and operations horizons. GTC is in agreement that some requirements in FAC-015-1 could alternatively be located within other standards such as TPL, MOD, etc. but recognizes the limits of the Project 2015-09 SAR.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
The companies support revised FAC-015-1.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
See related comment provided in Question 4.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
We believe it would be acceptable for the PC to use the RC's SOL methodology or develop their own methodology that does not conflict with the RC's approach. Once this standard is approved in final form, FAC-008 should be checked for interoperability and conformity with FAC-015 such that all ratings are covered(i.e., thermal, voltage, stability).	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Requirement R1 references application to "[e]ach Planning Coordinator and each of its Transmission Planners." However, Measure M1 only refers to the "Planning Coordinator." The same issue exists with respect to Requirements R2 and R3. ERCOT suggests aligning Measures M1, M2, and M3, with Requirements R1, R2, and R3 so that "Transmission Planners" are included in the Measures.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014. The measures will be updated.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Measures M1, M2 and M3 must be revised to include the Transmission Planner. Also we support NYISO's comment in regards to R1 and the conditions for using less limiting Facility Ratings. We support the first clause ("The Facility has higher Facility Ratings as a result…"). Allowing for less restrictive Facility Ratings because of differences in temperature	

seems inappropriate. If a different temperature is used by a planner, they should obtain the Facility Rating for that temperature. As for the possibility of submitting technical rationales to other entities, the requirement does not require buy-in by the receiving entities. Since the objective of this requirement is to align planning and operations, we respectfully submit that the Facility Ratings should be consistent in planning and operating models. Where there is disagreement, the more conservative value should be retained. This follows the approach in other standards where, in disagreement, the more conservative option is retained (for example, IRO-014). The same comment applies to R2 and R3 - that is, we consider that the receiving entity, in particular when it is the RC, should be able to enforce the use of the more conservative assumption. However, for those two requirements we note that a "planned upgrade, addition, or Corrective Action Plans" (like in R1) are not explicitly included as reasons to modify the limits. They should be included like in R1. We reiterate that the most conservative rating, limit should be used. However, we agree that facility upgrades or additions do not need to be referred to the RC for its confirmation. The VSL for R4, with its concern with the number of missing characteristics, does not make sense. If a PC or TP were to incorrectly communicate an instability - but only incorrect in one characteristic - this would be a lower VSL, but it could, if that error was important, make the communication useless and put the system at risk. The VSL should be severe, unless the error without consequence from an operational point of view. That is, if the RC was able to take correct actions as a consequence, then the error is without consequence. If the RC's actions were incorrect as a consequence of the error, then it should be Severe.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014. See response to NYISO comment	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments. The SDT has updated its proposal to consolidate the requirements in FAC-015 into a modified FAC-014.	

6. Discussions within the SDT indicated concerns with eliminating some of the components of the approved SOL definition. While the industry feedback was largely supportive of the draft SOL definition provided in the informal posting, the SDT modified the proposed definition to incorporate some of the concepts in the approved version. The SDT believes that the revised definition posted for ballot represents an improvement over the definition provided in the informal posting. Reference the SOL rationale document for more information. Do you agree with the proposed SOL definition?	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
"All" should be "The"	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. The use of the word "all" versus the word "the" was discussed at length in the development of the definition. The drafting team concluded that the use of the word "all" was a more accurate word selection because it eliminates any confusion of the inclusive nature of the term. It is important that the definition convey the notion that all Facility Ratings, System Voltage Limits, and stability limits are always SOLs at all times	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	

"All" should be "The"	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. The use of the word "all" versus the word "the" was discussed at length in the development of the definition. The drafting team concluded that the use of the word "all" was a more accurate word selection because it eliminates any confusion of the inclusive nature of the term. It is important that the definition convey the notion that all Facility Ratings, System Voltage Limits, and stability limits are always SOLs at all times.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP generally agrees with the proposed definition. However, when read separately from the technical rationale, the phrase "specified System configuration" is ambiguous and does not add clarity to the definition. SRP recommends adjusting the proposed definition to more completely explain the relationship between limits and specified System configurations.	
Likes 0	
Dislikes 0	
Response	
Response: Thank you for your feedback. The drafting team discussed this issue at length and determined that it is important to retain the "specified System configuration" language in the revised definition. The rationale document specifically addresses the reasoning for this position: *The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration,*	

there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
While the proposed definition is indeed a vast improvement over the existing, ambiguity is introduced when specifying "facility ratings" if the current definition of IROL (which relies on the definition of SOL) is kept. The singular of facility implies one facility but in practice, IROLs are often established a combination flows not specific to one facility but aggregations of facilities. These IROL MW flow limits may not trigger voltage or stability concerns. The definition should be modified to reflect this concept either by replacing "facility" with "facility(ies)" or by adding a dependent clause such as "facility ratings, either individually or taken in combinations, system voltage..."	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. Per the proposed revised definition, a Facility Rating is an SOL. While IROLs may be monitored as a sum of flows on several Facilities, this does not change the fact that a Facility Rating is an SOL. Phase two of the project will address IROLs and may include a revision of the IROL definition. The drafting team will keep your comments under consideration for that future work.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

While the definition is cleaner, the rationale document needs to be clear that exceeding a non-IROL SOL, particularly post contingency, is not a violation of any operating standard or criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. This comment, however, does not address the definition, but rather addresses compliance with operating Reliability Standards.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	Proposed definition of SOL.docx
Comment	
As written, it appears that an entity would need to provide multiple Facility Ratings, system voltage limits, and Stability Limits. AZPS recommends amending the proposed definition as shown in the attached WORD document to clarify that multiple limits are not required but may be provided if needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. While the drafting team agrees that the additional language (the second sentence in APS' proposed definition) is true, we do not believes that it substantially enhances the definition.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	

Comment	
NIPSCO believes that the start of the definition should read “SOL is the most limiting of”, as all limits should not be considered a System Operating Limit. We believe only the most limiting of the limits on a facility should be considered a System Operating Limit. If “all” ratings need to be monitored this would present a problem for many software platforms as there is no way to insert more than 3 or 4 ratings into a facility record.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. The drafting team discussed this issue at length and determined that the “most limiting of” language is inconsistent with the essence of the revision. Page 7 of the rationale document addresses this issue at length.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
“Monitoring and assessing” implies the process that is gone through to develop and use an SOL. This definition should focus on what an SOL is, not the process by which SOLs are found or how SOLs are used. *BPA suggested definition:* *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, to ensure reliable operation of the Bulk Electric System in both the pre- and post-Contingency operating states.*	
Likes 0	
Dislikes 0	
Response	

Thank you for your feedback. While the drafting team generally agrees with your comments, the monitoring and assessing language was added at the specific request of FERC staff. The proposed definition is problematic because of the use of the "to ensure reliable operation of" language.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCE supports the SDT's revised definition of SOL. The proposed definition improves clarity and eliminates ambiguity that was present in the previous definition. Furthermore, it eliminates several items the definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with MEC and supports the SDT's revised definition of SOL. The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	

Response	
Thank you for your feedback.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	Yes
Document Name	
Comment	
We agree with the proposed SOL definition. A minor comment is to change the singular term SOL to plural SOLs to align with the plural form for limits in the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Response Thank you for your feedback. The drafting team agrees with your suggestion.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
The companies support the revised definition.	

Likes 0	
Dislikes 0	
Response	
Thank you for your feedback.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
The proposed definition is an improvement. It removes the redundancy of pre- and post-Contingency operating states.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The proposed definition improves clarity, and eliminates ambiguity that was present in previous definition. Furthermore, it eliminates several items from previous definitions that were subject to interpretation.	
Likes 0	
Dislikes 0	

Response	
Thank you for your feedback.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Entergy supports the comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	

Answer	Yes
Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. Please reference the MRO response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We agree with the proposed SOL definition. A minor comment is to change the singular term SOL to plural SOLs to align with the plural form for limits in the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. The drafting team agrees with your suggestion.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
The MRO NSRF agrees with the proposed SOL definition. However, as stated in our response to question 1, we need additional clarification on the SOL expectation of the SDT. Is it your intent that each Facility has a thermal-based SOL or can a subset (Flowgates) be used to manage power flow on the system? This needs to be clearly stated in a requirement so that everyone is planning and operating the BES from the same understanding. Additionally, it's not clear if Normal Ratings and normal System Voltage Limits are considered SOLs, if you have higher Emergency Ratings or emergency System Voltage Limits for the Facilities. It could be interpreted to say Normal Ratings and normal System Voltage Limits aren't SOLs if you have higher Emergency Ratings and emergency System Voltage Limits. This understanding translates to compliance expectations in the IRO and TOP Standards for exceedances and when you must implement your Operating Plan. If we're relying on the SOL whitepaper to clarify, then some entities may choose not to follow it saying it's not mandatory. Since the SDT may not be able to answer compliance questions, we request NERC staff to draft a CMEP Practice Guide to inform the industry of the compliance expectations for SOLs as applied in the FAC, IRO and TOP standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. Each Facility has Facility Ratings, which are comprised of both a Normal Rating and one or more Emergency Ratings. For a given Facility, the full set of Facility Ratings, both the Normal Rating and all Emergency Ratings are SOLs at all times. Flowgates can certainly be used as a mechanism to manage power flow on the system; however, by definition, flowgate limits are not SOLs unless the flowgate defines a stability limit. Normal System Voltage Limits and Emergency System Voltage Limits are SOLs. All of these are SOLs all the time. The drafting team will communicate your recommendation to draft a CMEP Practice Guide as suggested.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
On behalf of our City Light SME: City Light agrees with the definition.	

Likes 0	
Dislikes 0	
Response	
Thank you for your feedback.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny	

Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
On behalf of our City Light SME: There is confusion about why the terms "SOL" and "IROL" need to be removed from some of these standards. In FAC-003, for example, shouldn't any element identified as part of a currently effective IROL be considered under the applicability section, not just things identified in the Planning Assessment?	
Likes 0	
Dislikes 0	
Response	
The term SOL and IROL as labels in the planning horizon are being retired, replaced by the concepts in the revised TPL 001 standard. As such any standard that used the term SOL or IROL as an identified facility from the Planning horizon needed a new method of identifying those important facilities. Standards that use the SOL or IROL from the Operating Horizon did not have the term removed.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

FAC-003-5 should be revised to align with the comments to FAC-015-1 in #5 above. Any requirements associated with a Near-Term Planning Assessment should align with the specific requirements in the approved TPL-001 Standard either the Operations Horizon or to a specific requirement within the TPL-001 Standard – R3.5 and R4.2.

Comments specifically for CIP-014-3: Applicability 4.1.1.3 should simply be removed. The proposed wording change causes confusion with the actual CIP-014 assessment, the whole purpose of which is to identify those Transmission substations that if rendered inoperable or damaged as a result of a physical attach could result in instability, Cascading or uncontrolled separation. The new proposed 4.1.1.3 would either create a circular argument or could inadvertently be interpreted to expand the scopes of TPL-001 and MOD-001. Any revisions to the requirements of the assessments in TPL-001 and MOD-001 should be made in those Standards, not through CIP-014.

Likes 0	
Dislikes 0	

Response

The drafting team believes the language offered in FAC-003 regarding a facility that if lost or degraded are expected to result in instances of instability, Cascading or uncontrolled separation does align with the TPL standard including the requirements that you referenced. The language offered in CIP-014 by the drafting team used similar language to FAC-003 and aligns with the analysis already done as part of the TPL 001 standard. The drafting team does not believe that it would create a circular argument, since it places no direct burden on the Planning Coordinator beyond communication. The team is assuming by MOD-001 you actually meet FAC-013, since MOD-001 address the determination of Available Transfer Capability and is not referenced in the standard.

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

While AEP has no objections to the proposed changes to CIP-014, FAC-013, PRC-002, PRC-023 and PRC-026, we do have concerns regarding 4.2.2, Transmission Facilities, within FAC-003. We believe additional text is needed here to ensure no lines are unintentionally excluded by

a) the timing of their being identified as part of an IROL and b) the timing of any facilities identified, which could lead to instability, Cascading, or uncontrolled separation within associated planning assessments. AEP recommends that this section be clarified in the following manner… *“Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation* ***or overhead transmission line operated below 200kV that have been established as part of an IROL by the Reliability Coordinator per IRO-014-3 R1.****”* AEP has chosen to vote negative on the proposed revisions to FAC-003, driven by the concerns expressed in this response.	
Likes 0	
Dislikes 0	
Response	
The drafting team believes that FAC-003 in addressing vegetation management applies to a longer period of time. As such the drafting team does not believe the designation of an IROL by the RC should be included in 4.2.2 since such a designation may be temporary or transitory in nature. The designation would not result in immediate vegetation management, and so it could be months or years before the vegetation management caught up with the designation, providing no practical benefit. If the RC does have an IROL below 200 kV that is expected to remain in place long enough that they would like it captured under FAC-003, they can coordinate with the Planning Coordinator or Transmission Planner to make sure it is captured in their study. Keep in mind this is only for facilities below 200 kV, all facilities above 200 kV Are captured by the standard.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
FAC-003-5 should have an implementation period once a study identifies a new Facility below 200 kV (Applicability Section) that could lead to instability, Cascading or uncontrolled separation. An entity needs the time to get that new Facility into it’s vegetation plan and meet the	

clearences. The way the **current FAC-003-4 and proposed Standard FAC-003-5** is written an entity is out of compliance once the new studied Facility is identified if it does not meet clearences and the entity would then need to self report. NPPD recommends an implementation period of up to 24 months to allow for the newly identified facility to be incorporated into it's vegetation plan and for clearences to be met. For the other Standards NPPD supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
The Implementation plan for FAC-003 standards allows for at least 12 months after the line is designated, changing that duration is not within the scope of this SDT.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF supports the effort of the SDT to eliminate planning-based SOLs and IROLs, but to ensure clarity of expectations the revisions to these standards need to directly map to the applicable TPL-001-4 contingency results that indicate unacceptable instances of instability, Cascading, or uncontrolled separation. As currently proposed, every instance of instability or tripping of multiple elements could be considered in scope for IROLs. Additionally, the SDT should consider that requirements to perform transfer capability studies were determined by the Standards Efficiency Review project to be for commercial purposes and proposed for retirement in the phase 1 SAR. Even though we realize the changes to CIP-002-6 are not in scope for this question and the modifications to the standard were given to the CIP SDT, the 2015-09 SDT is the one who understands the concept of IROLs. Therefore, we would appreciate the SDT passing the following concerns to the CIP SDT. The changes to CIP-002-6 criterion 2.6 and 2.9 do not add clarity. Unfortunately, the proposed changes to criterion 2.9 would bring in most SPS/RAS in the country because these systems are typically designed to avoid instability or a cascading outage scenario. Similarly, the proposed changes to criterion 2.6 substantially expands the scope of analysis. The current CIP-002-5.1 criterion 2.6	

language is very clear and narrow because it limits the evaluation to those Facilities that have been shown to impact a large area of the system (i.e. what it means to be an IROL). With the proposed changes, many more Facilities will need to be evaluated for instability, but the end result will still be very few Facilities on the list (and those that make it on the list probably have an SPS/RAS to mitigate the concern). This appears to be an unneeded expansion of the criterion whereas the current language is precise. The SDT should keep in mind that IROLs will still exist under the proposed FAC standard revisions for the operating horizon and, therefore, no change is needed to R2.6 or R2.9. We are not opposed to removing the Planning Coordinator in PRC-002 as an applicable functional entity and having the Reliability Coordinator as the only applicable regional function entity. However, we propose that the Time Horizon of all the Requirements be changed from "Long-term Planning" to "Operations Planning", to be consistent with the direct and indirect applicability of the Requirements to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
The current drafts discuss facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System. So as drafted the TP and PC would be identifying those facilities from their study that they believe meets that criteria, which may or may not include every instance of instability or tripping of elements if they do not adversely impact the reliability of the Bulk Electric System. The drafting team is aware of the effort to remove the FAC-013 transfer capability studies but until such time as they are actually removed the team must address them. Time Horizon: The drafting believes that these requirements are long term planning (1 year or greater) because when there is a violation there is a window of time to recover from the violation. The Time Horizon is the period of time to mitigate a violation, as such certainly some of the Reliability Coordinator functions are in the Operations Planning horizon, but data recording equipment issues are not a violation that has to be resolved within a day or even within the current season, nor can they be resolved that quickly depending on the lead time on the equipment. Because this equipment is for after the fact analysis, and not the real time prevention of an issue, the longer time horizon continues to be appropriate.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No

Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We agree with changes to reflect the elimination of Planning-based SOLs and IROLs for CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023. **However, we do not agree with the change to the PRC-026 standard. The Planning Coordinator requires the Reliability Coordinator to provide those SOLS that are based on angular stability in order to assess Criteria 1 and 2 of Requirement R1. We suggest revising Requirement R1 to require the Reliability Coordinator provide the Planning Coordinator with those SOLs that are based on angular stability.**	
Likes 0	
Dislikes 0	
Response	

Thank you for the support on CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023. For PRC-026 the responsibility is placed on the Planning Coordinator in the existing standard to provide the information to the Generator Owner and Transmission Owner and the drafting team maintained that requirement just moving away from the SOL and IROL language to better match the proposed paradigm. If the current practice in your area is that the Reliability Coordinator provides this information to the Planning Coordinator to fulfill this function than nothing in the revised standard would preclude that action.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends that CIP-014, FAC-003, FAC-015, PRC-023 and any other standards that reference "instability, uncontrolled separation, or Cascading" with the intent of replacing the term IROL be modified to include the qualifying phrase "*that adversely impact the reliability of either the interconnection or other Reliability Coordinator Area(s)*." This change aligns with the current NERC definitions for IROL and IROL Tv. NERC definitions: **Interconnection Reliability Operating Limit (IROL):** A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages *that adversely impact the reliability of the* Bulk Electric System. **Interconnection Reliability Operating Limit Tv (IROL Tv):** The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the *interconnection or other Reliability Coordinator Area(s)* becomes greater than acceptable. Each Interconnection Reliability Operating Limit's Tv shall be less than or equal to 30 minutes. BPA believes that the two NERC definitions work in conjunction to define when IROLs should be declared. The IROL definition identifies the BES, while the IROL Tv definition identifies an IROL Tv is used to protect the interconnection as a whole or other RC areas.	
Likes 0	
Dislikes 0	

Response	
The team revised the language to include the phrase as listed in the definition of IROL, “instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System”.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
Replacement of IROLs with vague unbounded terminology of “instability, uncontrolled separation, and cascading" isn't appropriate and is inferior to the current IROL approach. If IROLs aren't maintained, at a minimum, instability should be quantified with terms such as wide-area or a MW threshold such as the loss of 1,000 MW. The benefit of IROLs is the understanding of an impact threshold clearly understood and outlined in current IROL methodologies. Vague terminology in zero defect standards results in unnecessary violations, interpretations, and compliance guidance.	
Likes 0	
Dislikes 0	
Response	
The team revised the language to include the phrase as listed in the definition of IROL, “instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System”.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	

OKGE supports the comments provided by MRO NSRF. In addition, The SER Phase 1 project has already proposed that all the requirements in FAC-013-2 be retired. So, we don't see why this standard needs to be revised any further. We suggest that the SDT coordinate with the NERC SER team to discuss further.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF. The team discussed the FAC013-2 retirement with NERC SER and NERC Staff. Until the FAC 13's retirement is officially approved by FERC the drafting team must modify the standard as if it's going to continue.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Until the core standards of this project are settled NIPSCO is not ready to vote on these "dependent" standards and will likely Abstain at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No

Document Name	
Comment	
See MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Please see the MRO NERC Standards Review Forum response.	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy supports the elimination of Planning-based SOLs and IROLs; however, CenterPoint Energy does not agree with the changes to the standards listed above. By not incorporating language such as “that adversely impact the reliability of the BES” or some equivalent limiting phrasing into the proposed language used to replace IROL in these standards, the SDT may have expanded the scope of the applicability or requirement. Not all instances of instability rise to the level of adversely impacting the reliability of the BES, and these should not be considered in scope for the standards above.	
Likes 0	
Dislikes 0	
Response	
The team agrees and revised the language to include the phrase as listed in the definition of IROL, “instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System”.	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

The proposed responsibility shift in Requirement R5 from Responsible Entity (Planning Coordinator, where presently applicable) to Reliability Coordinator is outside of the scope of Project 2015-09 set forth by the SAR and does not align with the Long-term Planning Time Horizon of PRC-002, as the RC is responsible for real-time operating reliability of its area.

Additionally, Santee Cooper has concerns over shifting the responsibilities of Requirement R5 from the Responsibility Entity (Planning Coordinator) to the Reliability Coordinator at this stage in the existing PRC-002-2 implementation plan.

- The initial implementation deadline for Requirement R5 has past. Capital expenditure decisions have already been made based on the initial identification by the Responsible Entity of BES Elements for which DDR data is required per the prescriptive requirements of the standard.
- Changing the evaluator and spreading the minimum DDR coverage requirement over the Reliability Coordinator's historical simultaneous peak System Demand vs. the Responsible Entity could potentially change the results of the evaluation, and could potentially require additional equipment from an entity that is unbudgeted at this point.

Furthermore, there is a gap in the Implementation Plan for Project 2015-09 with regard to PRC-002-3.

- In the elements listed that shall remain applicable to the Implementation of PRC-002-3 R2, R3, R4, R6, R7, R8, R9, R10, R11, the Implementation Plan for Project 2015-09 does not address compliance requirements for a re-evaluated list from Requirement R1 or R5. The original PRC-002-2 gives entities three (3) years to be 100 percent compliant with a re-evaluated list from R1 or R5, allowing entities time to budget, design and commission any additional equipment that may be needed to comply. This omission creates a gap in the Implementation Plan, as R1 and R5 include mandatory re-evaluation at least once every five (5) years.

Multiple references to PRC-002-2 within the text of the draft standard have not been redlined, and should be replaced with PRC-002-3.

Multiple references to PRC-023-4 within the text of the draft standard have not been redlined, and should be replaced with PRC-023-5.

Multiple references to PRC-026-1 within the text of the draft standard have not been redlined, and should be replaced with PRC-026-2.	
Likes 0	
Dislikes 0	
Response	
The SDT believes placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which Dynamic Disturbance Recording (DDR) is required. The RC and TOP are the entities that identifies and monitors SOLs/IROLs within real time operations. Furthermore the RC is responsible for leading any investigation into events that would use this data. The TP and PC may assist in these efforts or even effectively lead them, but the standards and processes assign the responsibility to the RC. We have addressed the time window for implementation in the PRC-002 implementation plan and updated the standard references in all the documents.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
With the elimination of Planning –based SOLs and IROLs, the Standards drafting team has attempted to come up with alternate means of identification of facilities to fill the void, such as under Applicability Criterion 4.1.1.3 in CIP-014-3. The concern is that the use of terms like "instances of instability," "Cascading," and "uncontrolled separation" in place of IROL definition, is very vaguely defined in existing NERC standards and is highly subjective to individual entity's interpretation and application methodology. Further, there are no thresholds suggested that can be applied to derive these facilities from Near Term Transmission Planning Assessments. Such a list of facilities could vary considerably even between the Planning Coordinator's Assessment and the Transmission Planner's Assessment. Use of such vaguely defined criteria will subject entities to undue burden of evaluating lot more facilities under all of the above standards (CIP-014, FAC-003,	

FAC-013, PRC-002, PRC-023 and PRC-026) with increased risk of additional cost to be incurred. Suggest the standard drafting team come up with more specific methodology in place of IROL or delete this Criterion in CIP-014-3 and other applicable standards.	
Likes 0	
Dislikes 0	
Response	
The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS requests clarification on what contingencies are included in: · "Facilities that if lost or degraded" in CIP-014 and FAC-003; · "Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation" in B2 of Attachment B in PRC-023; and · "Elements associated with angular instability identified in Planning Assessments." AZPS suggests the following changes to FAC-013-3: · Remove R3	

· Remove "Reserved for future use" in R1.2 and update numbering accordingly Additionally, Planning Assessments, completed through TPL-001-4, include multiple categories of contingencies (P0-P7) and Extreme Events as detailed in Table 1 of TPL-001-4. Extreme Events referenced in TPL-001-4 should be excluded from those addressed through CIP-014, FAC-003, FAC-013, PRC-023 and PRC-026. To fail to do so could result in double-counting of contingencies. Further, to fail to do so could result in local impact contingencies being considered as a result of other contingency evaluations. For example, evaluation of Extreme Events under CIP-014 can bring in low impact substations despite the fact that the instability identified would only have a very small impact that is confined to a local area. Such identified local instability does not and should not result in required hardening under CIP-014. For this reason, only Planning Events from Table 1 of TPL-001-4 should be included. AZPS is further concerned that studies that have previously been completed would need to be restudied in accordance with the new standard in order to satisfy the 12 month timeline in the implementation plan even if the timeline prescribed in the existing requirement has a longer timeframe. For example, CIP-014-2 R1 requires studies every 30 calendar months. AZPS does not support doing an additional study for CIP-014-2 R1 before the 30 month deadline that we will have already created a scheduled for in order to be compliant with the new standard before the 12 month implementation date.

Likes 0	
Dislikes 0	

Response
Thank you for the comments. The contingencies that apply would be any contingencies studied under the TPL 001 that resulted in the described phenomena. For FAC-013 the drafting team made the minimum amount of changes since there is also an effort underway to retire FAC-013. To help clarify the types of system responses that could result in facility identification the team expanded the language to include "that adversely impact the reliability of the Bulk Electric System" so it better matches the current IROL. Given this caveat the team believes that all contingencies from the TPL assessment would be included unless they are excluded by the language in the particular standard. The "double counting" is a moot point since listing the same facility more than once would not result in any more burden than listing it a single time.

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

The changes for PRC-002 seems unrelated to the proposed FAC changes.

The proposed changes for CIP-014, PRC-023, and FAC-003 the replacement language is too broad. The Planning Assessment looks at extreme events which have low probability of occurring and for which corrective actions are not required. It doesn't seem reasonable that extreme events which result in instability, Cascading, or uncontrolled separation are now pulled into scope for CIP-014, PRC-023, and FAC-003 when CAP are not required by the TPL-001.

The proposed change to FAC-013 R1.3 seems unrelated to the proposed FAC change.

Likes 0	
Dislikes 0	

Response

The SDT believes placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which Dynamic Disturbance Recording (DDR) is required. The RC and TOP are the entities that identifies and monitors SOLs/IROLs within real time operations. Furthermore the RC is responsible for leading any investigation into events that would use this data. The TP and PC may assist in these efforts or even effectively lead them, but the standards and processes assign the responsibility to the RC. We have addressed the time window for implementation in the PRC-002 implementation plan and updated the standard references in all the documents.

The team agrees that the language was too broad and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".

The change to FAC-013 was to remove the SOL language and to clarify in 1.3 that the assumptions should be consistent with the Planning Coordinator's Planning Assessment which is a specific set, versus planning practices which is a broader term.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy believes there is inconsistency with the language used in the CIP-002-6 Draft of the impact of instability, Cascading, or uncontrolled separation. NV Energy would request that the SDT include "Wide Area Impacts" to the language revisions in CIP-014, FAC-003, and PRC-023:

CIP-014 Applicability 4.1.1.3 should read:

4.1.1.3 *Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result instances of* ***Wide Area impacts*** *such as instability, Cascading, or uncontrolled separation.*

FAC-003-5 Applicability 4.2.2 and 4.3.1.2 should read:

4.2.2. *Each overhead transmission line, operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of* ***Wide Area impacts*** *such as instability, Cascading, or uncontrolled separation.*

4.3.1.2. *Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of* ***Wide Area impacts*** *such as instability, Cascading, or uncontrolled separation; or …*

PRC-023-5 Attachment B (Criterion 2) should read:

B2. *The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of* ***Wide Area impacts*** *such as instability, Cascading, or uncontrolled separation.*	
Likes 0	
Dislikes 0	
Response	
The team agrees in principle to your suggestion, and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".	
Tommy Drea - Dairyland Power Cooperative - 5	
Answer	No
Document Name	
Comment	
DPC supports the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	No
Document Name	
Comment	

Comments: An administrative revision to PRC-023-5 is recommended to carry forward the approved implementation timing language from the PRC-023-3 Implementation Plan and the Errata to the Implementation Plan for the Revised Definition of "Remedial Action Scheme" (which included the PRC-023-4 revision). This non-substantive change to bring the current standard under revision into line with the currently approved version (and implementation notes) is necessary to avoid possible future errata revisions. A suggested revision is to include a footnote for the relevant sections in Section 4.2 Circuits (Sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6) as follows: **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. *1* **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.*1* **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. *1* **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. *1* *Footnote 1 suggested language:* *1.* Circuits identified by the Planning Coordinator in accordance with Requirement R6 shall be compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please review our changes to PRC-023 and the revised implementation plan, we think that we have addressed your concerns.	
Spencer Tacke - Modesto Irrigation District - 4	

Answer	No
Document Name	
Comment	
For CIP-014, FAC-003, PRC-023, and PRC-026, I think there needs to be a revison to every proposed redline change, that states "per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation." To those proposed change statements, I believe we need to add at the end of each one in all the referenced above Standards, the simple phrase ", or other Study." I believe this is needed because the TPL Assessments or Transfer Capability Assessments in themselves, don't necessarily require the type of extreme contingencies to be studied that would cause instability, Cascading, or uncontrolled separation. Hence to demonstrate the impact of these type of extreme contingencies (such as was done for the CIP-014 analysis), studies other than the Annual TPL Assessment or Transfer Capabilty Assessments might need to be completed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had discussed this extensively and while we agree that such conditions might be identified in other studies, the team did not want to include language in the standard that could create a shadow requirement for the Planning Coordinator or Transmission Planner to run additional studies beyond those required in TPL 001. The Planning Coordinator could provide those additional studies for the other party to use on a voluntary basis or the Planning Coordinator could insure that the next years TPL-001 includes the conditions that would trigger the event, and thereby be able to communicate it in a binding fashion.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy has concerns with the language proposed as a replacement to the IROL language in these standards. The language, *"per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation,"* is too broad as written, and appears to bring TPL-001-4 Extreme Events into scope and other single & multiple contingency events well beyond the scope of the original single contingencies specified in R2 of FAC-010/011 and specified in R5.1.1 of the proposed FAC-011-4 to identify SOL's and IROl's. We believe more limiting language is appropriate. CIP-014- Duke Energy feels that the draft language is too broad (see above). FAC-003- As stated above, we have concerns with the appearance of an expansion of scope. This would be in conflict with the original intent of the standard which did not include such events. We believe more limiting language is appropriate. Also, there appears to be inconsistent use of Planning Coordinator or Transmission Planner (as used in the Applicability section), and Categories 1A-4B which references the Planning Coordinator only. Was it the drafting team's intent that only the Planning Coordinator apply to those Categories? PRC-002- Duke Energy does not support the change from Responsible Entity to Reliability Coordinator in R5. This would be a significant departure from current industry practices since the RC does not currently have assess operation in the Long Term Planning Horizon. This would prompt the need for Reliability Coordinators to revise current processes, and include steps to reach out to entities in its RC Area for this information. We fail to see the reliability benefit of transferring historically planning related activities to the Reliability Coordinator. PRC-023- Duke Energy feels that the draft language is too broad (see above). We believe more limiting language is appropriate. PRC-026- Duke Energy feels that the draft language is too broad (see above). We believe more limiting language is appropriate. Also, there appears to be a grammatical error in R1. Consider removing the "a" before "limiting the output of a generator".	
Likes 0	
Dislikes 0	
Response	
IROL Replacement language: The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".	

CIP-014: See revised replacement language above, in addition CIP-014 FAC-003: The team felt it was best to have a single entity responsible in those criteria. PRC-002: The SDT believes placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which Dynamic Disturbance Recording (DDR) is required. The RC and TOP are the entities that identifies and monitors SOLs/IROLs within real time operations. Furthermore the RC is responsible for leading any investigation into events that would use this data. The TP and PC may assist in these efforts or even effectively lead them, but the standards and processes assign the responsibility to the RC. We have addressed the time window for implementation in the PRC-002 implementation plan and updated the standard references in all the documents. PRC-023: Please see if our revised language addresses your concern. PRC-026: Please see if our revised language addresses your concern.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
FAC-013-3 The companies recommend keeping FAC-013-3 R1.3 without revision and preserve the words “planning practices.”	

The proposed R1.3 revisions, replacing “planning practices” with the NERC Glossary term, “Planning Assessments,” effectively assigns TPL assessment criteria and requirements to FAC-013. Such an outcome is inconsistent with the FAC-013 purpose to “…reliably transfer energy in the Near-Term Transmission Planning Horizon.” Also, by effectively assigning TPL assessment criteria and requirements to FAC-013, assessments are duplicated and establish similar compliance obligations over multiple Standards. Furthermore, by having similar compliance obligations over multiple Standards creates a compliance conundrum when either Standards yield a similar issue of noncompliance. **CIP-014 FAC-003 PRC-002 PRC-023 and PRC-026** The companies support the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes that leaving the language “planning practice” in place is too broad and unclear as to what planning practice, when, should be used in the FAC-013 study. Keep in mind 1.3 only requires a statement that the assumptions and criteria used are consistent with the Planning Assessment, but they don’t require them to be identical. 1.4 then provides the opportunity for the Planning Coordinator to explain what they are doing.	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	
Exelon GO agrees with commenets filed by Exelon TO	
Likes 0	

Dislikes 0	
Response	
Please see the response to the Exelon TO comments.	
John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon LSE supports Exelon TO comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the Exelon TO comments.	
Becky Webb - Exelon - 6	
Answer	No
Document Name	
Comment	
Exelon MKT suports Exelon TO comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the Exelon TO comments.	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	

The proposed redline changes in CIP-014 and FAC-003 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. The FAC-013 and PRC-002 changes are acceptable. With regard to PRC-023, the changes made to Criterion B2 have made it very unclear. The language "is selected by" infers that there is some sort of optional or judgement, but there is no indication of what that should be based on. Additionally, referring to Planning Assessment is too vague. Planning Assessments include consideration of extreme events, but these seem inappropriate for consideration in PRC-023. If the decision is made to keep B2 similar to what has been drafted, please change "Planning Assessments" to "assessments", as this would allow for consideration of any available inputs. Proposed language is shown below. Similarly, for PRC-026, R1 criterion 2 is too restrictive by using the term "Planning Assessments". This should be changed to "technical assessment" as shown below. Also in PRC-026, page numbers should be added to the Guidelines and Technical Basis section.

PRC-023 Criterion B2 further modification in bold below:

*The circuit is selected **identified** by the Planning Coordinator based on assessments **of P0 – P7 Planning Events** that identify instances of instability, Cascading, or uncontrolled separation.* *Additional revision for PRC-026, R1 criterion 2 in bold below:* *Elements associated with angular instability identified in **technical assessments including but not limited to** Planning Assessments.*	
Likes 0	
Dislikes 0	
Response	
For CIP-014, FAC-003, PRC-023 and PRC-026 the drafting team believes that specifying the Planning Coordinator TPL 001 Planning Assessment is the correct study to point at. The team discussed allowing other studies and assessments as well, but ultimately believed that leaving this to broad could have unintended consequences, such as implying that the Planning Coordinator should have these other studies and make them available. If the Planning Coordinator finds issues that need to be addressed through other studies, those can always be incorporated in to the next years TPL 001 Planning assessment Requiring them to be in the Planning Assessment also means that the items identified by the Planning Coordinator may also be triggering a corrective action plan. Thank you for your support on FAC-013 and PRC-002 For PRC-023 the drafting team further limited the events to the near term horizon and planning events.	
Terry BIlke - Midcontinent ISO, Inc. - 2	

Answer	No
Document Name	
Comment	

MISO agrees with retiring FAC-010.

With regard to PRC-026_R1, the first sub-bullet appears to either have a grammatical error or it should be revised for clarity. "Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or RAS…". Suggestion is to remove the words "…addressed by a…".

Likes 0	
Dislikes 0	
Response	

Thank you for your support. The drafting team adjusted the wording in PRC-026_R1 to remove a stray "A" and that should help with the grammatical error.

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2; - ISO New England, Inc. - 2 - NPCC

Answer	No
Document Name	
Comment	

The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002.

The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.	
Likes 0	
Dislikes 0	
Response	
For CIP-002 please forward questions to the CIP team. The team discussed extensively using language that allowed the Planning Coordinator and Transmission Planner to bring in other studies or assessments in addition to their Planning Assessment. However ultimately the team decided that the required Assessment that places requirement on the Planning Coordinator and Transmission Planner was the only study that should be referenced. First of all because it is a study where the Planning Coordinator and Transmission Planner are required to do something with the results and second to avoid creating questions regarding "what other studies/assessments". There is nothing that would preclude a Planning Coordinator or Transmission Planner from identifying something in studies or assessments through the year, and then including that study/assessment in their annual Planning Assessment – thereby passing the information on to the end user in the context of the standard.	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	No
Document Name	
Comment	

The question is not clear. We do not have the same position in all the standards listed here.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion, Con Ed and NBPower	
Answer	No
Document Name	
Comment	

It is our understanding that 'Planning Assessment' in the proposed change from referring to IROLs to "..., per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation" refers to studies performed for the Near-Term Transmission Planning Horizon per NERC Reliability Standard TPL-001-4. The term Planning Assessment is in the NERC 'Glossary of Terms Used in NERC Reliability Standards' defined as "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies." To reduce the risk of continued inconsistency, we propose to add "technical analyses such as its" to the text replacing the previous reference to IROLs as well as a minor editorial change to the reference to Transfer Capability assessment in all applicable NERC Reliability Standards listed in Project 2015-09 as well as, if approved, to NERC Reliability Standard CIP-006-2. Hence, we proposed the text replacing the reference to IROLs to read "..., per technical analyses such as its Planning Assessment of the Near-Term Transmission Planning Horizon or the Planning Coordinator's Transfer Capability assessment, as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation."

We agree with changes to reflect the elimination of Planning-based SOLs and IROLs for CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023.

However, we do not agree with the change to the PRC-026 standard. The Planning Coordinator requires the Reliability Coordinator to provide those SOLS that are based on angular stability in order to assess Criteria 1 and 2 of Requirement R1. We suggest revising Requirement R1 to require the Reliability Coordinator provide the Planning Coordinator with those SOLs that are based on angular stability.	
Likes 0	
Dislikes 0	
Response	
The team discussed extensively using language that allowed the Planning Coordinator and Transmission Planner to bring in other studies or assessments in addition to their Planning Assessment. However ultimately the team decided that the required Assessment that places requirement on the Planning Coordinator and Transmission Planner was the only study that should be referenced. First of all because it is a study where the Planning Coordinator and Transmission Planner are required to do something with the results and second to avoid creating questions regarding "what other studies/assessments". There is nothing that would preclude a Planning Coordinator or Transmission Planner from identifying something in studies or assessments through the year, and then including that study/assessment in their annual Planning Assessment – thereby passing the information on to the end user in the context of the standard. Thank you for your support on CIP-014, FAC-003, FAC-013, PRC-002, and PRC-023. For PRC-026 the current standard does not require the Planning Coordinator to get this information from the Reliability Coordinator, if that is your current practice nothing in the changes would preclude the Reliability Coordinator from continuing to give the information to the Planning Coordinator.	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

Replacing the term IROL with the IROL definition may lead to inconsistent determinations by different Entities.	
Likes 0	
Dislikes 0	
Response	
The Drafting team used the full definition of IROL instead of the partial definition used earlier, and leaving the term IROL in place would be ineffective since the drafting team is retiring FAC-010 and thereby the usage of the term IROL within planning space.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA is concerned that the language being proposed to replace defined terms is too broad and creates too many questions regarding how to comply with the standards.	
Likes 0	
Dislikes 0	
Response	
The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	

Answer	No
Document Name	
Comment	

CIP-014:

The SDT proposed the following language for CIP-014-3 Applicability 4.1.1.3:

Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

ERCOT proposes that "instability" be changed to "system instability."

ERCOT believes the use of the term "instability" is too broad and could be interpreted to include localized instability events that do not have a widespread impact. This suggestion is consistent with the concern noted in the NERC Methods for Establishing IROLs Task Force (MEITF) report at p. vii:

Specifically, the PRR acknowledged that the use of the word "instability" in the IROL definition is particularly problematic as this term can be interpreted to include any and every instance of instability that spans the entire spectrum of consequences and severity of impact—ranging from one extreme where instability results in the loss of a single small unit to the other extreme where instability results in widespread outage of a major portion of an RC area or beyond. The PRR contended that localized, contained instances of instability that affect a small amount of load have little to no impact on the reliability of the BES and do not warrant IROL establishment.

The MEITF report defines the term "system instability" as:

The inability of the Bulk Power System,* for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a Disturbance.

*Refers to the remaining portion of the interconnected Bulk Power System, with the exception of the Elements disconnected as a result of the Disturbance.

ERCOT agrees that not all instances of instability warrant IROL establishment. For this reason, and to remain consistent with the MEITF report, ERCOT recommends that the proposed language for CIP-014-3 Applicability 4.1.1.3 be modified to include "system instability" rather than "instability."

ERCOT notes there are other instances in various Requirements where the use of "system instability" may be more appropriate than "instability."

FAC-003: None

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

FAC-013: None

FAC-015:

It appears there may be a copy/paste typo. ERCOT suggests using “steady-state voltage,” instead of “stability.”

PRC-002: None

PRC-023: None

PRC-026:

ERCOT is concerned that the phrase, “Elements associated with angular instability identified in Planning Assessments” in R2, Criteria No. 2 creates ambiguity and an unintended expansion in the scope of PRC-026.

ERCOT suggests deleting the current draft Criteria 1 & 2 and replacing them with the following in order to more closely align with the intent of both PRC-026 and Project 2015-09:

1. Generator(s) where an angular stability constraint exists that is addressed by limiting the output of the generator or by a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s). 2. Elements that are monitored in order to enforce an existing angular stability constraint.	
Likes 0	
Dislikes 0	
Response	
CIP-014 The team agrees and revised the language to include the phrase as listed in the definition of IROL, “instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System”. FAC-003, FAC-013, PRC-002, PRC-023: Thank you for your support. PRC-026: The drafting team made some revisions to the language that hopefully has addressed your concerns?	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP identifies the following adjustments that must be made to avoid confusion to the Reliability Standards: FAC-003-5: (references made to redline version) -Page 10 – Delete the reference to R2	

-Page 13 R1 VSL should reference FAC-003-5 Table 2 not FAC-003-4

-Page 24-25 – Delete all references to R2

PRC-026 (references in the Redline)

-Entire document: change the references to PRC-026-1 Attachment A & B to PRC-026-1 Attachment A&B

PRC-023-5 (references redline document)

-Entire Document: Adjust the references to PRC-023-4 to PRC-023-5

Likes 0	
Dislikes 0	

Response

For PRC-026 thank you for your feedback, the team has made some changes based on your comments.

For PRC-023-5 the changes suggested have been made.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

CIP-014-3: Per the CIP-014 Guidance, ITC believes the CIP-014 Applicability 4.1.1.1 to 4.1.1.4 should mirror the CIP-002-5.1a Attachment 1 criterion 2.4-2.7. The proposed changes for CIP-014 Applicability 4.1.1.3 do match the proposed (Project 2016-02 Modifications to CIP Standards) changes for CIP-002-5.1a Attachment 1 criterion 2.6. However, ITC believes any discussion pertaining to CIP-014 Applicability is

better suited for "Project 2016-02 Modifications to CIP Standards. In addition, ITC remains concern that the originating changes from FAC Reliability standards diminish the need for a process to ensure the RC/PC/TO entities are including for evaluation facilities and assets to support the intent of the NERC CIP standards. " PRC-002-3: Changes made do not affect ITC's current PRC-002 process.

Likes 0	
Dislikes 0	

Response
Thank you for your comment on CIP-014, the SDT has been working with the Project 2016-02 on the changes.
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment
Regarding 4.1.1.3 in the Functional Entities section of CIP-014-3, Southern believes that the verbiage ***"would adversely affect reliability of the Bulk Electric System"*** should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL (see below): **4.1.1.3** Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ***would adversely affect reliability of the Bulk Electric System***.

Regarding 4.2.2 in the Functional Entities section of FAC-003-5, Southern believes that the verbiage ***"would adversely affect reliability of the Bulk Electric System"*** should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ***would adversely affect reliability of the Bulk Electric System.***

Regarding B2 in the Criteria section of PRC-023-5, Southern believes that the verbiage "***would adversely affect reliability of the Bulk Electric System"*** should be added to the proposed wording to ensure that the changes are more in line with the current definition of an IROL (see below):

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation that ***would adversely affect reliability of the Bulk Electric System***.

Regarding PRC-002-3, Southern does not believe that the Responsible Entity (under Functional Entities 4.1) should be changed.

Southern Company's main concern with the proposed changes is not the substitution of the IROL term with the three outcomes – instability, Cascading, or uncontrolled separation – our main concern is the prescriptive nature of naming Planning Coordinator studies which is beyond existing IROL methodologies, and the use of the unbounded term "instability". For example, compliance with present TPL-001-4 standard for Planning (P) events (and proposed TPL-001-5) requires that any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated as per the Corrective Action Plan. While instability, Cascading, or uncontrolled separation do not have to be mitigated for Extreme Events in TPL-001-4/(future 5), as the name implies, Extreme Events are rare events.

Southern Company, like many other companies, has an IROL methodology that is largely based in RC and PC stability input. This methodology identifies SOLs and any subset of the identified SOLs that should be elevated to IROLs. As such, we suggest that references to

specific compliance-based studies such as TPL-001 and FAC-013 be removed and allow the use of in-place proven study methodologies to determine and communicate scenarios that are realistic potential instances of instability, Cascading, or uncontrolled separation. (reference CIP-014, FAC-003, PRC-023 and PRC-026).	
Likes 0	
Dislikes 0	

Response

CIP-014 & PRC-023: The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System".

PRC-002: The SDT believes placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which Dynamic Disturbance Recording (DDR) is required. The RC and TOP are the entities that identifies and monitors SOLs/IROLs within real time operations. Furthermore the RC is responsible for leading any investigation into events that would use this data. The TP and PC may assist in these efforts or even effectively lead them, but the standards and processes assign the responsibility to the RC. We have addressed the time window for implementation in the PRC-002 implementation plan and updated the standard references in all the documents.

The team discussed extensively using language that allowed the Planning Coordinator and Transmission Planner to bring in other studies or assessments in addition to their Planning Assessment. However ultimately the team decided that the TPL Assessment was the best reference point. Using variations on the expression "studies, assessments" without the term Planning Assessment could allow a Planning Coordinator or Transmission Planer to not do any studies and thereby not pass any data. Referencing other studies in addition to the Planning Assessment would than raise questions on what other studies were the Planning Coordinator and Transmission Planner expected to perform. There is nothing that would preclude a Planning Coordinator or Transmission Planner from identifying something in studies or assessments through the year, and then including that study/assessment in their annual Planning Assessment – thereby passing the information on to the end user in the context of the standard.

Randy MacDonald - NB Power Corporation - 1

Answer	No
Document Name	
Comment	
Looking at FAC-003-5 as an example: The application of the text "Facility that if lost or degraded are expected to result in instances of instability Cascading, or uncontrolled separation", while used to identify those lines (under 200 kV) that are applicable to FAC-003-5, appears too discretionary. Is the intent to identify those elements that if lost/degraded and in combination with a contingency is expected to result in instances of ....?	
Likes 0	
Dislikes 0	
Response	
The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System". As for which facility, the facility that is lost or degraded would be the contingency facility.	
William Sanders - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
See comments above.	
Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

CIP-014:

- The applicability section 4.1.1.3 in CIP-014-3 specifies that if instances of instability, Cascading or uncontrolled separation occurred due to the loss of a facility in the Near-term planning assessment, it would be applicable to the CIP-014 analysis.
- The term "instances of instability" is not clear and needs to be defined clearly to eliminate confusion of what qualifies a facility to be assessed in CIP-014.

FAC-003:

- Violation Severity Levels (Table 1) (pgs. 13-16)
- Since R2 was removed from the table on pg. 14, there is no documentation of the severity levels for lines above 200 kV that are not "identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation"
- FAC-003 1.4 Additional Compliance Information (pg. 10)
    - There appears to be a typo regarding the footnote that is referenced:

▪ "Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:" ▪ Should this be changed to "footnote 4"? This typo has been in FAC-003-3 & FAC-003-4 versions. ▪ This change will ensure we are not required to submit tree related outages that are "beyond our control".	
Likes 0	
Dislikes 0	
Response	
CIP-014: The team agrees and revised the language to include the phrase as listed in the definition of IROL, "instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System". FAC-003: The comments regarding R2 were applied to the standard. Footnote 4 was also corrected.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
See comments above.	
Likes 0	
Dislikes 0	
Response	

Please see response above.	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

The modifications to the standards are not consistent.

We note three key differences:

1. In PRC-002-2, the PC function is removed leaving the RC function, whereas in the other standards (e.g. CIP-014-3), the RC function is removed, leaving the PC function. We disagree with this change.

When PRC-002-2 was being developed, the Drafting Team was aware that different Functional Entities across the continent would be the appropriate parties to be responsible for the Standard's requirements. This was presented to industry in the Request for Comments posted November 1, 2013 through December 16, 2013. The Responsible Entity was defined in Section 4 of the Introduction in PRC-002-2 accordingly. Nothing in section R5 supposes that the SOL are planning SOL; the PC can obtain the relevant SOL for their determination per requirement R5 of FAC-014-3.

2. In the CIP-013 and FAC-003, the Near-Term Transmission Planning Horizon of the Planning Assessment is specified, whereas it is not specified in for the two PRC standards. The two PRC standards should use the same approach. In particular, issues in the long-term horizon of the Planning Assessment should not be relevant to the application of the PRC-023 and PRC-026 standards.

3. In PRC-023, the text "that identify instances of instability, Cascading, or uncontrolled separation" is different than the text "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation" used in the other standards. The use of different text implies differences that are hard to interpret. We support that the same text should be used in these different standards.

Also, we point out a minor typo in PRC-026-2 : R1 – (…) Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by [a] limiting the output of a generator (…)	
Likes 0	
Dislikes 0	
Response	
PRC-002: The SDT believes placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which Dynamic Disturbance Recording (DDR) is required. The RC and TOP are the entities that identifies and monitors SOLs/IROLs within real time operations. Furthermore the RC is responsible for leading any investigation into events that would use this data. The TP and PC may assist in these efforts or even effectively lead them, but the standards and processes assign the responsibility to the RC. We have addressed the time window for implementation in the PRC-002 implementation plan and updated the standard references in all the documents. PRC-023: The drafting team revised the language to be more consistent with the other standards and to be limited to planning events. The language allows the Planning Coordinator or Transmission Planner to select circuits that meet those criteria, but doesn't require the PC or TP to select every circuit that meets the criteria, since not every circuit that meets that criteria may be a good candidate for PRC-023. PRC-026: Thank you the typo was addressed.	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes

Document Name	
Comment	
NRECA agrees with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by NRECA. NRECA agrees with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

Recommend adding the word "Facility" to the below applicability item from FAC-003-5. With the current wording, radial lines that are 200kV or higher are in-scope of FAC-003-5. This modificaiton allows the radial line exclusion to be utilized, but should not otherwise impact the scope of FAC-003. **4.2.1.** Each overhead transmission line **Facility** operated at 200kV or higher.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the drafting team discussed making this change but ultimately did not since it was not within our scope and we didn't believe the addition of the word substantially changed the meaning of the requirement sub part.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst Votes in the Affirmative but provides the following comment for consideration. For PRC-026-2, R1. Criteria 1, ReliabilityFirst comment on the following proposed language: "Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s)." The "a" between "by" and "limiting" seems out of place and ReliabilityFirst recommends removal.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment, we addressed the stray A	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
GTC agrees with the modifications to the standards impacted by the retirement of FAC-010. Further GTC notes the following: • The removal of the Planning Coordinator as an entity responsible for Requirement 5 in PRC-002 represents a material change to the Applicability section of the standard. GTC agrees with this change and the SDT's rationale that "placing responsibility solely on the Reliability Coordinator adds clarity and consistency for the task of identifying the BES Elements for which dynamic Disturbance recording (DDR) data is Required." • The proposed modification to FAC-013 is an improvement to this standard. • The streamlined language in the proposal for FAC-003 is a much needed improvement. • The other modifications represent an appropriate replacement for the planning SOL/IROLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	

- We believe the proposed language FAC-003, 4.2.2 should be revised for clarity. The proposed R 4.2.2 identifies a line to which the standard is applicable, "Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation."

Based on recent planning assessments and studies related to transfer capability, the PC would not ever add such facilities. If a loss of a single line (whether or not below 200kV) would result in cascading, that would result in the utility failing to comply with TPL-001. Since a PC would have to be compliant with TPL-001-4, the PC would ensure such a sub-200kV line would never be added to the system, resulting in a null set for such lines, rendering 4.2.2 meaningless.

- We also recommend adding the language: "that adversely impact the reliability of the Bulk Electric system" following references to "uncontrolled separation." This addition would bring the language in alignment with the Glossary of terms definition of IROL.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. There may be a window of time between when the PC identified the facility and when a corrective action plan or other project was in place to address the issue where FAC-003 could be applied. We also expanded the language to include "adversely impact the reliability of the Bulk Electric System for planning events."

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment

Clarifying language should be added to PRC-026 Requirement R1 Criteria 1 to indicate that the Reliability Coordinator will provide the information concerning angular stability constraints to the Planning Coordinator. This would be in alignment with the intent of revised FAC-014 R5.2 and its sub-requirements.

Likes 0	
Dislikes 0	
Response	
The Drafting team discussed this and did not believe it was necessary to prescribe that the Planning Coordinator receive those constraints from the Reliability Coordinator. The standard is written as the Planning Coordinator is responsible for either developing those limits or gathering those limits from the Reliability Coordinator and passing them on. Given that PRC-026 involves relay protection, which is a long term investment, it's appropriate that it be based on longer term problems that the Planning Coordinator studies.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We agree with the changes as they are applied consistently throughout the standards. However, if the SDT changes the approach as stated in the previous comments, these areas will need to be revisited. In terms of FAC-003-5 and CIP-014-3, there may be an un-intended consequence of potentially pulling in facilities below 200 kV for compliance with both standards. The language is also not consistent in the FAC-003-5 applicability section, and the Sustained Outage categories beginning on page 10. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and the comment on Page 10, the drafting team has addressed the inconsistency.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
The SPP Standards Review Group (SSRG) recommends that the drafting team consider IROLs in Phase 2 of this Project 2015-09. As discussed at the September 2018 Planning Committee (PC) Meeting, although this project includes IROLs, the drafting team's feedback to the PC was to focus on only the SOL for this commenting period (Phase I). During Phase II, the drafting team will put more focus on the IROL. This is a reasonable suggestion given that all relevant materials pertaining to the IROL were approved at that most recent meeting and couldn't be implemented in the Phase I comment period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the drafting team agrees that IROL's are not within scope for this phase.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE appreciates the SDT reviewing the standards to identify those impacted by the retirement of FAC-010. Regarding the Implementation Plan, under General Considerations, it states that for PRC-002-3, PRC-023-4, and PRC-005-3, the elements of the prior implementations plans shall remain applicable and are incorporated herein by reference. Texas RE's understanding is that although the effective date of the new proposed versions of these standards is "the first day of the first calendar quarter that is twelve calendar months after the effective date of the applicable governmental authority's order approving the standards", the prior versions of	

the implementation plans indicated in the general considerations section remains in place. If this is the case, it may be more clear to list out those exact dates that remain in place for the prior versions of the standards. Texas RE also recommends including a question about the implementation plan on each comment form going forward to encourage stakeholders to review the implementation plans.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments, we have gone through and revised the implementation plans which will hopefully address your concerns.	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura McLeod - NB Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	
Document Name	
Comment	
The question is not clear. We do not have the same position in all the standards listed here.	
Likes 0	
Dislikes 0	

Response	
Thank you for the feedback, on future comment forms feel free to address each standard individually in your comment.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	
Document Name	
Comment	
The question is not clear. We do not have the same position on all the standards listed here.	
Likes 0	
Dislikes 0	
Response	
Thank you for the feedback, on future comment forms feel free to address each standard individually in your comment.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC is not opposed to removing the Planning Coordinator in PRC-002 as an applicable functional entity and having the Reliability Coordinator as the only applicable regional functional entity. However, ATC proposes that the Time Horizon for all the Requirements be revised from "Long-term Planning" to "Operations Planning," to be consistent with the direct and indirect applicability of the Requirements to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	

Time Horizon: The drafting believes that these requirements are long term planning (1 year or greater) because when there is a violation there is a window of time to recover from the violation. The Time Horizon is the period of time to mitigate a violation, as such certainly some of the Reliability Coordinator functions are in the Operations Planning horizon, but data recording equipment issues are not a violation that has to be resolved within a day or even within the current season, nor can they be resolved that quickly depending on the lead time on the equipment. Because this equipment is for after the fact analysis, and not the real time prevention of an issue, the longer time horizon continues to be appropriate.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	
Document Name	

Comment

While Hydro One is in general agreement with the proposed retirements and modifications, we recommend the addition of "identified by the Transmission Planner" as follows to the phrase that is to replace occurrences of SOL/IROL:

"Facilities identified by the Transmission Planner that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation"

This change would clarify that it is the TPs that are expected to identify these facilities for the TOs and TOPs.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The SDT revised the wording in all these standards and hopefully the revised wording address your concern.

Updated
Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through October 17, 2018

Now Available

A 45-day formal comment period has been extended through **8 p.m. Eastern, Wednesday, October 17, 2018** for the following standards, implementation plan and proposed definition:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon (retirement)
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology (Updated)
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- Implementation Plan
- Proposed Definition - System Operating Limit

The following have been reposted due to identified typographical errors. The comment period has been extended to provide stakeholders adequate time to review the updated documents:

- FAC-015-1 - Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology
- FAC-015-1 - Requirement Rationale

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the proposed revisions to the FM and FMTD. If you experience any difficulties in using the electronic form, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, September 24, 2018.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

- *Passwords expire every* ***6 months*** *and must be reset.*
- *The SBS* ***is not*** *supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

Initial and additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 24 – October 17, 2018.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

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3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 2 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 258
Total Ballot Pool: 308
Quorum: 83.77
Weighted Segment Value: 53.22

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	88	1	28	0.424	38	0.576	0	8	14
Segment: 2	8	0.6	4	0.4	2	0.2	0	1	1
Segment: 3	68	1	22	0.415	31	0.585	1	5	9
Segment: 4	15	0.6	3	0.3	3	0.3	0	1	8
Segment: 5	67	1	25	0.472	28	0.528	0	4	10
Segment: 6	50	1	15	0.395	23	0.605	0	4	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	8	0.8	6	0.6	2	0.2	0	0	0
Totals:	308	6.4	107	3.406	127	2.994	1	23	50

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Negative	Comments Submitted
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Negative	Comments

					Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
		Nathaniel			

1	Portland General Electric Co.	Clague		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Negative	No Comment Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A

6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
5	Exelon	Cynthia Lee		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
4	Austin Energy	Jun Hua		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
					Third-Party

1	Lakeland Electric	Larry Watt		Negative	Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted

4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A

1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A

5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A

6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
3	CPS Energy	Glenn Pressler	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 2 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 258
Total Ballot Pool: 313
Quorum: 82.43
Weighted Segment Value: 59.02

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	34	0.486	36	0.514	0	4	16
Segment: 2	8	0.6	4	0.4	2	0.2	0	1	1
Segment: 3	70	1	27	0.482	29	0.518	1	3	10
Segment: 4	15	0.7	4	0.4	3	0.3	0	0	8
Segment: 5	68	1	28	0.519	26	0.481	0	2	12
Segment: 6	50	1	18	0.45	22	0.55	0	2	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	313	6.5	126	3.836	119	2.664	1	12	55

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
5	Edison International - Southern California Edison	Selene Willis		Negative	Comments

	Company				Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Negative	Third-Party Comments
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A

6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
		Michael			Third-Party

1	City Utilities of Springfield, Missouri	Bowman		Negative	Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Negative	No Comment Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
					Comments

3	Exelon	Kinte Whitehead		Negative	Submitted
5	Exelon	Cynthia Lee		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
4	Austin Energy	Jun Hua		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A

3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A

3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A

5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A

10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments

4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea	None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
3	CPS Energy	Glenn Pressler	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-015-1 AB 2 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 257
Total Ballot Pool: 313
Quorum: 82.11
Weighted Segment Value: 59.79

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	35	0.507	34	0.493	0	5	16
Segment: 2	8	0.6	4	0.4	2	0.2	0	1	1
Segment: 3	70	1	26	0.473	29	0.527	0	4	11
Segment: 4	15	0.8	4	0.4	4	0.4	0	0	7
Segment: 5	68	1	30	0.566	23	0.434	0	2	13
Segment: 6	50	1	20	0.5	20	0.5	0	2	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	313	6.6	130	3.946	113	2.654	0	14	56

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		None	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted

1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted

1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted

5	Exelon	Cynthia Lee		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted
4	Austin Energy	Jun Hua		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
			Brandon		Comments

3	Florida Municipal Power Agency	Joe McKinney	McCormick	Negative	Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments

2	New York Independent System Operator	Gregory Campoli	Negative	Comments Submitted
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons	Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker	Affirmative	N/A
1	Lower Colorado River Authority	William Sanders	Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley	Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner	Affirmative	N/A
6	Santee Cooper	Michael Brown	Affirmative	N/A
3	Santee Cooper	James Poston	Affirmative	N/A
5	Santee Cooper	Tommy Curtis	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz	Negative	Comments Submitted
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
3	Platte River Power Authority	Jeff Landis	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail	Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeff Icke	None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich	Abstain	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Black Hills Corporation	George Tatar	Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell	Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk	Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A

6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	Salt River Project	Steven Cobb		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments

1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
3	CPS Energy	Glenn Pressler	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits CIP-014-3 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 312
Quorum: 83.65
Weighted Segment Value: 67.65

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	44	0.647	24	0.353	0	7	15
Segment: 2	7	0.6	3	0.3	3	0.3	0	1	0
Segment: 3	70	1	33	0.623	20	0.377	0	6	11
Segment: 4	16	0.9	5	0.5	4	0.4	0	0	7
Segment: 5	68	1	35	0.686	16	0.314	0	6	11
Segment: 6	50	1	25	0.641	14	0.359	0	4	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	312	6.5	155	4.397	81	2.103	0	25	51

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		None	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
	Berkshire Hathaway Energy - MidAmerican				Comments

1	Energy Co.	Terry Harbour		Negative	Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
5	Entergy	Jamie Prater		Negative	Comments

					Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Jeff Johnson	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A

6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A

5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A

6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A

3	Imperial Irrigation District	Glen Allegranza		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Edison International - Southern California Edison	Kenya Streeter		None	N/A

	Company			
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Affirmative	N/A
3	Eversource Energy	Christopher McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
3	Empire District Electric Co.	Kalem Long	None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Negative	Comments Submitted
3	JEA	Garry Baker	Affirmative	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp	Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted

1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Negative	Comments Submitted
1	Exelon	Daniel Gacek	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-003-5 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 264
Total Ballot Pool: 313
Quorum: 84.35
Weighted Segment Value: 67.46

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	43	0.623	26	0.377	0	6	15
Segment: 2	7	0.5	4	0.4	1	0.1	0	2	0
Segment: 3	71	1	32	0.582	23	0.418	0	6	10
Segment: 4	16	0.9	5	0.5	4	0.4	0	0	7
Segment: 5	67	1	33	0.623	20	0.377	0	4	10
Segment: 6	51	1	23	0.59	16	0.41	0	5	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	313	6.4	150	4.317	90	2.083	0	24	49

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted

1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
5	Entergy	Jamie Prater		Negative	Comments Submitted

1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted

1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A

6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A

5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A

2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A

1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp	Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
				Comments

5	Salt River Project	Kevin Nielsen	Negative	Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Negative	Comments Submitted
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-013-3 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 257
Total Ballot Pool: 303
Quorum: 84.82
Weighted Segment Value: 77.07

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	44	0.721	17	0.279	0	12	14
Segment: 2	8	0.6	6	0.6	0	0	0	1	1
Segment: 3	69	1	30	0.652	16	0.348	0	13	10
Segment: 4	16	0.7	6	0.6	1	0.1	0	2	7
Segment: 5	64	1	33	0.688	15	0.313	0	8	8
Segment: 6	49	1	21	0.618	13	0.382	0	9	6
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	303	6.2	149	4.779	62	1.421	0	46	46

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne		None	N/A

		Guttormson			
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County,	LeRoy Patterson		None	N/A

	Washington				
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
			Douglas		Comments

3	Westar Energy	Bryan Taggart	Webb	Negative	Submitted
5	Westar Energy	Derek Brown		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
	Edison International - Southern California Edison				Comments

3	Company	Romel Aquino	Negative	Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
3	Lakeland Electric	Patricia Boody	Negative	Third-Party Comments
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A

1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Negative	Comments Submitted
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A

1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	Affirmative	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A

1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-002-3 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 264
Total Ballot Pool: 313
Quorum: 84.35
Weighted Segment Value: 75.07

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	49	0.71	20	0.29	0	6	15
Segment: 2	8	0.7	5	0.5	2	0.2	0	1	0
Segment: 3	71	1	36	0.667	18	0.333	0	7	10
Segment: 4	16	0.9	7	0.7	2	0.2	0	0	7
Segment: 5	68	1	39	0.736	14	0.264	0	5	10
Segment: 6	50	1	24	0.667	12	0.333	0	7	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	313	6.5	169	4.879	68	1.621	0	27	49

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A

1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur	Joe Tarantino	Affirmative	N/A

		Starkovich			
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments

6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	Affirmative	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A

3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-023-5 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 316
Quorum: 83.86
Weighted Segment Value: 69.27

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	44	0.657	23	0.343	0	8	15
Segment: 2	8	0.7	4	0.4	3	0.3	0	1	0
Segment: 3	72	1	34	0.654	18	0.346	0	9	11
Segment: 4	17	0.9	5	0.5	4	0.4	0	1	7
Segment: 5	69	1	37	0.725	14	0.275	0	7	11
Segment: 6	50	1	24	0.667	12	0.333	0	7	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	316	6.5	157	4.503	74	1.997	0	34	51

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Negative	Comments

					Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A

5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
		Arthur			

1	Sacramento Municipal Utility District	Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
					Third-Party

3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
		David			

5	CMS Energy - Consumers Energy Company	Greyerbiehl		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille	April Owen		None	N/A

	County			
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster	None	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
3	National Grid USA	Brian Shanahan	Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services,	Katherine	Negative	Comments

	Inc.	Prewitt		Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Affirmative	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-026-2 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 313
Quorum: 83.39
Weighted Segment Value: 71.98

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	46	0.73	17	0.27	0	12	15
Segment: 2	8	0.6	1	0.1	5	0.5	0	1	1
Segment: 3	70	1	33	0.702	14	0.298	0	12	11
Segment: 4	16	0.8	6	0.6	2	0.2	0	1	7
Segment: 5	68	1	39	0.78	11	0.22	0	8	10
Segment: 6	51	1	26	0.722	10	0.278	0	7	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	313	6.3	160	4.535	59	1.765	0	42	52

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A

10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments

3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan		Abstain	N/A

		Connell			
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
			Brandon		Comments

3	Ocala Utility Services	Neville Bowen	McCormick	Negative	Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A

4	City Utilities of Springfield, Missouri	John Allen	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson	Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A

1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
		Christopher			

3	Eversource Energy	McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Negative	Comments Submitted
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted

3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 2 OT
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 247
Total Ballot Pool: 305
Quorum: 80.98
Weighted Segment Value: 69.93

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	40	0.615	25	0.385	0	7	17
Segment: 2	8	0.4	4	0.4	0	0	0	3	1
Segment: 3	69	1	30	0.566	23	0.434	1	4	11
Segment: 4	14	0.7	4	0.4	3	0.3	0	0	7
Segment: 5	66	1	35	0.673	17	0.327	0	2	12
Segment: 6	49	1	22	0.611	14	0.389	0	3	10
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	305	6.1	145	4.266	82	1.834	1	19	58

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments

					Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A

1	Seminole Electric Cooperative, Inc.	Mark Churilla	Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	None	N/A
6	Black Hills Corporation	Brooke Voorhees	None	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White	Negative	No Comment Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette	None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
4	Austin Energy	Jun Hua	None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Abstain	N/A
1	Eversource Energy	Quintin Lee	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Abstain	N/A
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
3	AEP	Leanna Lamatrice	Affirmative	N/A

1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
1	LS Power Transmission, LLC	John Seelke		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A

1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted

1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron		Affirmative	N/A

		Ghodooshim			
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
					Third-Party

1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments
1	Salt River Project	Steven Cobb		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party

					Comments
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits Proposed Definition - System Operating Limit IN 1 DEF
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: DEF
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 259
Total Ballot Pool: 310
Quorum: 83.55
Weighted Segment Value: 82.26

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	58	0.806	14	0.194	0	3	15
Segment: 2	8	0.6	5	0.5	1	0.1	0	1	1
Segment: 3	70	1	43	0.796	11	0.204	0	5	11
Segment: 4	16	0.9	7	0.7	2	0.2	0	0	7
Segment: 5	66	1	43	0.782	12	0.218	0	2	9
Segment: 6	50	1	29	0.763	9	0.237	0	4	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.6	6	0.6	0	0	0	0	0
Totals:	310	6.5	195	5.347	49	1.153	0	15	51

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	None	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A

1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Negative	Third-Party Comments
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A

1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Negative	Third-Party Comments
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
		Meaghan			

5	Public Utility District No. 1 of Chelan County	Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A

3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A

1	Seattle City Light	Pawel Krupa	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson	Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
3	Lakeland Electric	Patricia Boody	Negative	Third-Party Comments
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Negative	Third-Party Comments
6	Black Hills Corporation	Eric Scherr	Negative	Third-Party Comments
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A

1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A

2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Affirmative	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted
3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted

3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Affirmative	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-011-4 Non-binding Poll AB 2 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 236
Total Ballot Pool: 290
Quorum: 81.38
Weighted Segment Value: 46.2

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	19	0.422	26	0.578	21	16
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	67	1	17	0.415	24	0.585	15	11
Segment: 4	14	0.5	3	0.3	2	0.2	2	7
Segment: 5	63	1	19	0.463	22	0.537	10	12
Segment: 6	45	1	8	0.308	18	0.692	12	7
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	8	0.6	6	0.6	0	0	2	0
Totals:	290	5.8	79	3.208	92	2.592	65	54

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Allen Klassen		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
		Robert			

6	Ameren - Ameren Services	Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A

6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Jun Hua		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A

1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A

5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments

					Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A

5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
3	CPS Energy	Glenn Pressler	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 Non-binding Poll AB 2 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 236
Total Ballot Pool: 294
Quorum: 80.27
Weighted Segment Value: 51.96

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	22	0.478	24	0.522	19	17
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	68	1	22	0.489	23	0.511	12	11
Segment: 4	14	0.6	4	0.4	2	0.2	1	7
Segment: 5	65	1	22	0.524	20	0.476	9	14
Segment: 6	46	1	10	0.37	17	0.63	11	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	8	0.6	6	0.6	0	0	2	0
Totals:	294	5.9	93	3.561	86	2.339	57	58

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A

5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Allen Klassen		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb		Affirmative	N/A

		Schrayshuen			
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted

5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Jun Hua		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A

1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted

1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A

1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A

1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A

6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
3	CPS Energy	Glenn Pressler	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-015-1 Non-binding Poll AB 2 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 235
Total Ballot Pool: 294
Quorum: 79.93
Weighted Segment Value: 52.22

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	22	0.478	24	0.522	19	17
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	68	1	21	0.477	23	0.523	12	12
Segment: 4	14	0.6	4	0.4	2	0.2	1	7
Segment: 5	65	1	23	0.535	20	0.465	8	14
Segment: 6	46	1	11	0.393	17	0.607	10	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	8	0.6	6	0.6	0	0	2	0
Totals:	294	5.9	94	3.583	86	2.317	55	59

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A

4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
1	Westar Energy	Allen Klassen		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A

6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Richard Vine		Abstain	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments

				Submitted
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank	None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu	Affirmative	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Abstain	N/A
4	Austin Energy	Jun Hua	None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen	Abstain	N/A
1	Eversource Energy	Quintin Lee	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
3	AEP	Leanna Lamatrice	Abstain	N/A
1	Long Island Power Authority	Robert Ganley	Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula	Affirmative	N/A
3	Duke Energy	Lee Schuster	Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund	None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams	Negative	Comments Submitted
		Stephanie		

5	Cleco Corporation	Huffman	Louis Guidry	Abstain	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Black Hills Corporation	George Tatar		Negative	Comments Submitted

3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		None	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
10	ReliabilityFirst	Anthony		Affirmative	N/A

		Jablonski			
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Great River Energy	Michael Brytowski		None	N/A
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
1	Imperial Irrigation District	Jesus Sammy		Affirmative	N/A

		Alcaraz		
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea	None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak	None	N/A
1	Corn Belt Power Cooperative	larry brusseau	None	N/A
5	Bonneville Power Administration	Scott Winner	Negative	Comments Submitted
3	CPS Energy	Glenn Pressler	None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	None	N/A
1	CPS Energy	Gladys DeLaO	None	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits CIP-014-3 Non-binding Poll IN 1 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 300
Quorum: 82
Weighted Segment Value: 65.52

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	28	0.636	16	0.364	23	18
Segment: 2	7	0.3	2	0.2	1	0.1	4	0
Segment: 3	70	1	29	0.63	17	0.37	13	11
Segment: 4	15	0.7	5	0.5	2	0.2	1	7
Segment: 5	65	1	28	0.683	13	0.317	14	10
Segment: 6	48	1	13	0.542	11	0.458	16	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	300	5.9	114	4.091	60	1.809	72	54

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		None	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
					Comments

6	Bonneville Power Administration	Andrew Meyers		Negative	Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A

8	David Kiguel	David Kiguel		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Jeff Johnson	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
1	Peak Reliability	Michael Granath		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted

1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A

5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A

1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted

5	BC Hydro and Power Authority	Helen Hamilton Harding	Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson	Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Abstain	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon	Abstain	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Abstain	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Comments Submitted

5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
3	JEA	Garry Baker		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
1	NB Power Corporation	Nurul Abser	None	N/A
6	Great River Energy	Donna Stephenson	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A

2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A

NERC Balloting Tool

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Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-003-5 Non-binding Poll IN 1 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 300
Quorum: 82
Weighted Segment Value: 64.77

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	28	0.609	18	0.391	21	18
Segment: 2	7	0.3	3	0.3	0	0	4	0
Segment: 3	69	1	28	0.636	16	0.364	14	11
Segment: 4	15	0.7	5	0.5	2	0.2	1	7
Segment: 5	65	1	27	0.659	14	0.341	14	10
Segment: 6	49	1	14	0.538	12	0.462	15	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	300	5.9	114	4.142	62	1.758	70	54

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted

1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A

6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A

1	Eversource Energy	Quintin Lee		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A

5	Santee Cooper	Tommy Curtis		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A

10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Abstain	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon	Abstain	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Abstain	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A

3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A

3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
1	NB Power Corporation	Nurul Abser	None	N/A
6	Great River Energy	Donna Stephenson	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A

3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

[redacted]

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-013-3 Non-binding Poll IN 1 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 242
Total Ballot Pool: 293
Quorum: 82.59
Weighted Segment Value: 68.52

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	83	1	30	0.682	14	0.318	22	17
Segment: 2	7	0.3	3	0.3	0	0	3	1
Segment: 3	69	1	25	0.658	13	0.342	20	11
Segment: 4	15	0.7	6	0.6	1	0.1	1	7
Segment: 5	62	1	25	0.676	12	0.324	16	9
Segment: 6	47	1	13	0.542	11	0.458	17	6
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	293	5.9	111	4.357	51	1.543	80	51

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted

3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted

3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Negative	Comments Submitted
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
5	Westar Energy	Derek Brown		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon	Negative	Comments

			McCormick		Submitted
1	Westar Energy	Allen Klassen		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A

6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Lakeland Electric	Patricia Boody		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Abstain	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted

1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter	None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Negative	Comments Submitted
3	National Grid USA	Brian Shanahan	Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker	Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	None	N/A
6	Great River Energy	Donna Stephenson	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services,	Katherine	Negative	Comments

	Inc.	Prewitt		Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-002-3 Non-binding Poll IN 1 NB
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 301
Quorum: 81.73
Weighted Segment Value: 74.44

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	34	0.723	13	0.277	20	18
Segment: 2	7	0.3	3	0.3	0	0	4	0
Segment: 3	70	1	32	0.711	13	0.289	14	11
Segment: 4	16	0.7	6	0.6	1	0.1	1	8
Segment: 5	64	1	32	0.762	10	0.238	12	10
Segment: 6	49	1	18	0.667	9	0.333	14	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	301	5.9	134	4.663	46	1.237	66	55

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A

5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
1	SaskPower	Wayne		None	N/A

		Guttormson			
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A

6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A

5	Santee Cooper	Tommy Curtis		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A

3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Abstain	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon	Abstain	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Abstain	N/A
3	Lakeland Electric	Patricia Boody	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A

1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A

5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	None	N/A
6	Great River Energy	Donna Stephenson	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

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Segment: 5	66	1	30	0.732	11	0.268	14	11
Segment: 6	49	1	16	0.615	10	0.385	15	8
Segment: 7	1	0.1	1	0.1	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

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Ballot Pool Members

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1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted

10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A

6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A

3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
3	Austin Energy	W. Dwayne		Affirmative	N/A

		Preston		
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Abstain	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon	Abstain	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Abstain	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
3	Lakeland Electric	Patricia Boody	Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik	Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	None	N/A

3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A

5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	None	N/A
6	Great River Energy	Donna Stephenson	Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	Aaron Smith	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Abstain	N/A
3	Exelon	Kinte Whitehead	Abstain	N/A
5	Exelon	Cynthia Lee	Abstain	N/A
6	Exelon	Becky Webb	Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-026-2 IN 1 ST
Voting Start Date: 10/8/2018 12:01:00 AM
Voting End Date: 10/17/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 261
Total Ballot Pool: 313
Quorum: 83.39
Weighted Segment Value: 71.98

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	90	1	46	0.73	17	0.27	0	12	15
Segment: 2	8	0.6	1	0.1	5	0.5	0	1	1
Segment: 3	70	1	33	0.702	14	0.298	0	12	11
Segment: 4	16	0.8	6	0.6	2	0.2	0	1	7
Segment: 5	68	1	39	0.78	11	0.22	0	8	10
Segment: 6	51	1	26	0.722	10	0.278	0	7	8
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	313	6.3	160	4.535	59	1.765	0	42	52

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A

10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Abstain	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments

3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Third-Party Comments
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
4	Georgia System Operations Corporation	Benjamin Winslett		None	N/A
1	JEA	Ted Hobson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan		Abstain	N/A

		Connell			
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
			Brandon		Comments

3	Ocala Utility Services	Neville Bowen	McCormick	Negative	Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Westar Energy	Derek Brown		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
1	Westar Energy	Allen Klassen		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
4	Austin Energy	Jun Hua		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A

4	City Utilities of Springfield, Missouri	John Allen	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	Abstain	N/A
1	CMS Energy - Consumers Energy Company	James Anderson	Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh	Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Theresa Martinez	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Shivaz Chopra	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Eric Egge	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Negative	Third-Party Comments
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	N/A
1	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A

1	American Transmission Company, LLC	Douglas Johnson		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Negative	Third-Party Comments
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
		Christopher			

3	Eversource Energy	McKinnon	None	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Negative	Comments Submitted
3	JEA	Garry Baker	Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Randy MacDonald	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke	Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Robert Kondziolka	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz	Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz	Abstain	N/A
1	Exelon	Daniel Gacek	Negative	Comments Submitted

3	Exelon	Kinte Whitehead	Negative	Comments Submitted
5	Exelon	Cynthia Lee	Negative	Comments Submitted
6	Exelon	Becky Webb	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Steven Cobb	Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik	Abstain	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Richard Vine	Abstain	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi	Abstain	N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17
45-day formal comment period with additional ballot	08/27/18 – 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology.

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances;

7.1.2. SOL exceedances of stability limits;

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[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation;

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and

7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention:
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

   1.3. Compliance Monitoring and Enforcement Program:
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of

				Requirement R3 into its SOL methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL methodology.
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-

		communicated and if so, with what priority, but failed to include one of the Parts 7.2.1 through 7.2.2.	time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.1.1 through 7.1.5.	time Assessments must be communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to	The Reliability Coordinator failed to provide its new or revised SOL methodology to	The Reliability Coordinator failed to provide its new or revised SOL methodology to	The Reliability Coordinator failed to provide its new or revised SOL methodology to

	one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	TBD	Adopted by the NERC Board	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17
45-day formal comment period with additional ballot	08/27/18 – 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology.

R2. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless ~~the Reliability Coordinators~~its SOL ~~M~~methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. ~~Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and provide~~ Define the method for determining ~~the~~ common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection. ~~to be used in operations;~~

~~**3.0.** Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and~~

~~**4.0.** Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.~~

~~**M5.**~~**M3.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~unit~~ angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator ~~.~~Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion ~~extent~~modeled of the Reliability Coordinator Area, ~~as well as~~ and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

~~M6.~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)~~ for the area under study~~. The SOL ~~M~~methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events~~ for use in determining stability limits and performing OPAs and RTAs~~:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block~~, with Normal Clearing,~~ in a monopolar or bipolar high voltage direct current system.

5.2. ~~Identify any~~Specify additional single or multiple Contingency events or types of Contingency events, if any~~ for use in performing Operational Planning Analysis and Real-time Assessments~~.

~~**5.3.** Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.~~

~~5.4.~~5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-01~~5~~4-~~1~~3, Requirement R~~48~~7, to use in determining stability limits.

~~M7.~~M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. ~~The actual pre-~~System performance for no Contingenc~~y~~ies ~~state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following:

6.1.1. Steady state ~~F~~flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state ~~V~~voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded-.~~Instability, Cascading or uncontrolled separation do not occur.~~

~~**6.1.3.**~~**6.1.4.** Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric~~e~~ System does not occur.[1]

6.2. ~~The evaluation of potential~~System performance for the single Contingencies listed in Part 5.1.~~1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following:

6.2.1. Steady State post-Contingency ~~F~~flow through Facilities ~~are~~ within applicable Emergency Ratings.~~, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings.~~ Steady state post-Contingency ~~F~~flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency ~~V~~voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria~~e~~ defined in the Reliability Coordinator's SOL methodology are met[1]. ~~Instability, Cascading or uncontrolled separation do not occur.~~

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[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

~~6.2.3.~~6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electrice System does not occur[1].

6.3. ~~The evaluation of~~ System performance for applicable ~~the potential~~ Contingencies identified in Part 5.2 ~~against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System- does not occur.

~~6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.~~

~~6.5.~~6.4. In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

~~M8.~~M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances;

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation;

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and

7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R7.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL ~~M~~methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~7.1.~~8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~7.2.~~8.2. Criteria for determining when ~~violating~~ exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

~~M10.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement ~~R6~~R8.

~~**R8.** Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator. The method shall address the periodicity for communicating established SOLs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M10.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.~~

~~R10.~~R9. Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~10.1.~~9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

~~10.2.~~9.2. Each of the following entities prior to the effective date of the SOL ~~m~~Mmethodology:

~~10.2.1.~~9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

~~10.2.2.~~9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

~~10.2.3.~~9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

~~10.2.4.~~9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

~~M11.~~M9. Acceptable evidence ~~that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8~~ may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL ~~M~~methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine which ~~the applicable~~ owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine which ~~the applicable~~ owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of	The Reliability Coordinator failed to incorporate two of	The Reliability Coordinator failed to incorporate three of the Parts of Requirement	The Reliability Coordinator failed to incorporate four or more of the Parts of

	the Parts of Requirement R3 into its SOL ~~M~~methodology.	the Parts of Requirement R3 into its SOL ~~M~~methodology.	R3 into its SOL ~~M~~methodology.	Requirement R3 into its SOL ~~M~~methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL ~~M~~methodology.
R5.	N/A	N/A~~The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.~~	The Reliability Coordinator failed to incorporate ~~two~~ one of the Parts 5.2 ~~, 5.3,~~ or 5.~~4~~ 3 of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL ~~M~~methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2~~, 5.3,~~ and 5.~~4~~ 3 of Requirement R5 into its SOL ~~M~~methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL ~~M~~methodology.
R7	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances

		time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.2.1 through 7.2.2.	identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.1.1 through 7.1.5.	identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.
R~~7~~8.	N/A	N/A	The Reliability Coordinator failed to include Part ~~7~~8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL m~~M~~ethodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (criteria for developing any associated IROL T_v) in its SOL ~~M~~methodology.	The Reliability Coordinator failed to include Parts ~~7~~8.1 and ~~7~~8.2 in its SOL ~~M~~methodology.

~~**R8.**~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.~~	~~The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.~~
R9.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance

				with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	TBD	Adopted by the NERC Board	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL methodology.

R4. Each Reliability Coordinator shall establish stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Owner and Generation Owner. This communication shall include those Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:**
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

   1.3. **Compliance Monitoring and Enforcement Program**
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria	described in its respective Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed

			in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   ~~**4.1.1.**~~**4.1.2.** Reliability Coordinator

   4.1.3. Transmission Operator

   ~~**4.1.2.**~~**4.1.4.** Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology (SOL ~~M~~methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL ~~M~~methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

R3. ~~The~~ Each Transmission Operator shall provide its SOLs to its Reliability Coordinator ~~in accordance with its Reliability Coordinator's SOL Methodology~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

R4. Each Reliability Coordinator shall establish stability limits ~~to be used in operations~~ when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area ~~or other Reliability Coordinator Areas~~ in accordance with its SOL ~~M~~methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of ~~the associated~~ system conditions associated with ~~that are specific to~~ the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.~~5~~6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

~~**R6.** Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*~~

~~**M6.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, that demonstrates the Transmission Operator and Reliability Coordinator determined SOL exceedances in accordance with its Reliability Coordinator's SOL Methodology when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses.used the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.~~

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission

Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Owner and Generation Owner. This communication shall include those Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention:
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator, ~~or~~ Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

   1.3. Compliance Monitoring and Enforcement Program
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL ~~M~~methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to ~~determine~~ establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~6~~5.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria~~N/A~~	described in its respective Reliability Coordinator's SOL methodology.~~A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.~~
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- TOP-001-6 Transmission Operations
- IRO-008-3 Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits
- CIP-014-2 Physical Security
- FAC-003-4 Transmission Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements
- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- TOP-001-5 Transmission Operations
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms “System Voltage Limit” and “System Operating Limit” shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority’s order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms “System Voltage Limit” and “System Operating Limit” shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-6, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, CIP-014-2, PRC-002-2, PRC-023-4, and PRC-005-3 are incorporated herein by reference and shall remain applicable to FAC-003-5, CIP-014-3, PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
    - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
    - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
    - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.

- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
    - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the TO or the RC.
- *PRC-023-4: Time Period to address new designations is retained:*
    - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- *FAC-013-2*
    - Following effective date of FAC-013-3, the Planning Coordinator shall update their methodology and perform their assessment either:
        - Within the calendar year the standard becomes effective if the assessment was not completed that calendar year under FAC-013-2
        - Within the next calendar year after the standard is effective if the assessment had been completed within that calendar year under FAC-013-2
- *CIP-014-3*
    - Following effective date of FAC-013-3, the Transmission Owner shall perform the risk assessment Required in Requirement R1 within
        - 30 calendar months of its last assessment if it had identified one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection in that prior assessment; or
        - 60 calendar months of its last assessment if it had not identified any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.
- *PRC-002-3, Requirement R5*
    - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.

- *PRC-023-4*
    - Each Planning Coordinator shall conduct tits first assessment under PRC-23-4 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-23-3, whichever occurs first.
- *PRC-026-2*
    - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they most complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
    - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
    - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- ~~FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology~~
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- TOP-001-6 Transmission Operations
- IRO-008-3 Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits
- CIP-014-2 Physical Security
- FAC-003-4 Transmission Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements
- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- TOP-001-5 Transmission Operations
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

~~Prerequisite Approvals~~

~~In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-~~

~~002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.~~

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, ~~FAC-015-1~~CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, ~~FAC-015-1~~CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, ~~FAC-015-1~~CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-6, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, ~~FAC-015~~CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, CIP-014-2, PRC-002-2, PRC-023-4, and PRC-005-3 are incorporated herein by reference and shall remain applicable to FAC-003-5, CIP-014-3, PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
  - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.

- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
    - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
    - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
    - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the TO or the RC.
- *PRC-023-4: Time Period to address new designations is retained:*
    - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- *FAC-013-2*
    - Following effective date of FAC-013-3, the Planning Coordinator shall update their methodology and perform their assessment either:
        - Within the calendar year the standard becomes effective if the assessment was not completed that calendar year under FAC-013-2
        - Within the next calendar year after the standard is effective if the assessment had been completed within that calendar year under FAC-013-2
- *CIP-014-3*
    - Following effective date of FAC-013-3, the Transmission Owner shall perform the risk assessment Required in Requirement R1 within
        - 30 calendar months of its last assessment if it had identified one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection in that prior assessment; or
        - 60 calendar months of its last assessment if it had not identified any Transmission

stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

- *PRC-002-3, Requirement R5*
  - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.
- *PRC-023-4*
  - Each Planning Coordinator shall conduct tits first assessment under PRC-23-4 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-23-3, whichever occurs first.
- *PRC-026-2*
  - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they most complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
  - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
  - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

~~Initial Performance of Periodic Requirements~~

~~FAC-014-3 Requirement R5, Parts 5.1 and 5.2~~

~~The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18 - 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Physical Security

2. **Number:** CIP-014-3

3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates: See Implementation Plan

6. Background:

Reliability Standard CIP-014-3 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or
- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner’s and Transmission Operator’s facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	Long-term Planning	Medium	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	
3	TBD	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Section 4 Applicability

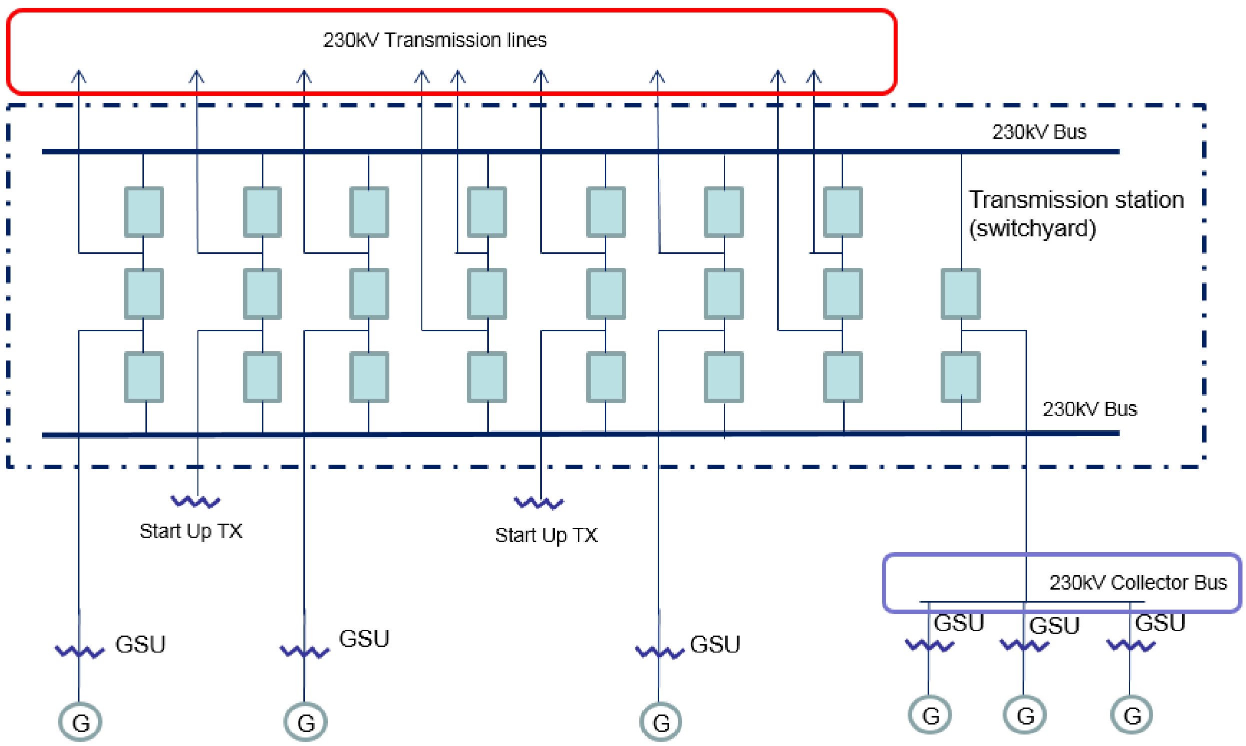
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security

(*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System for planning events. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase “Transmission stations or Transmission substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or

Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential

4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within

120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

  Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

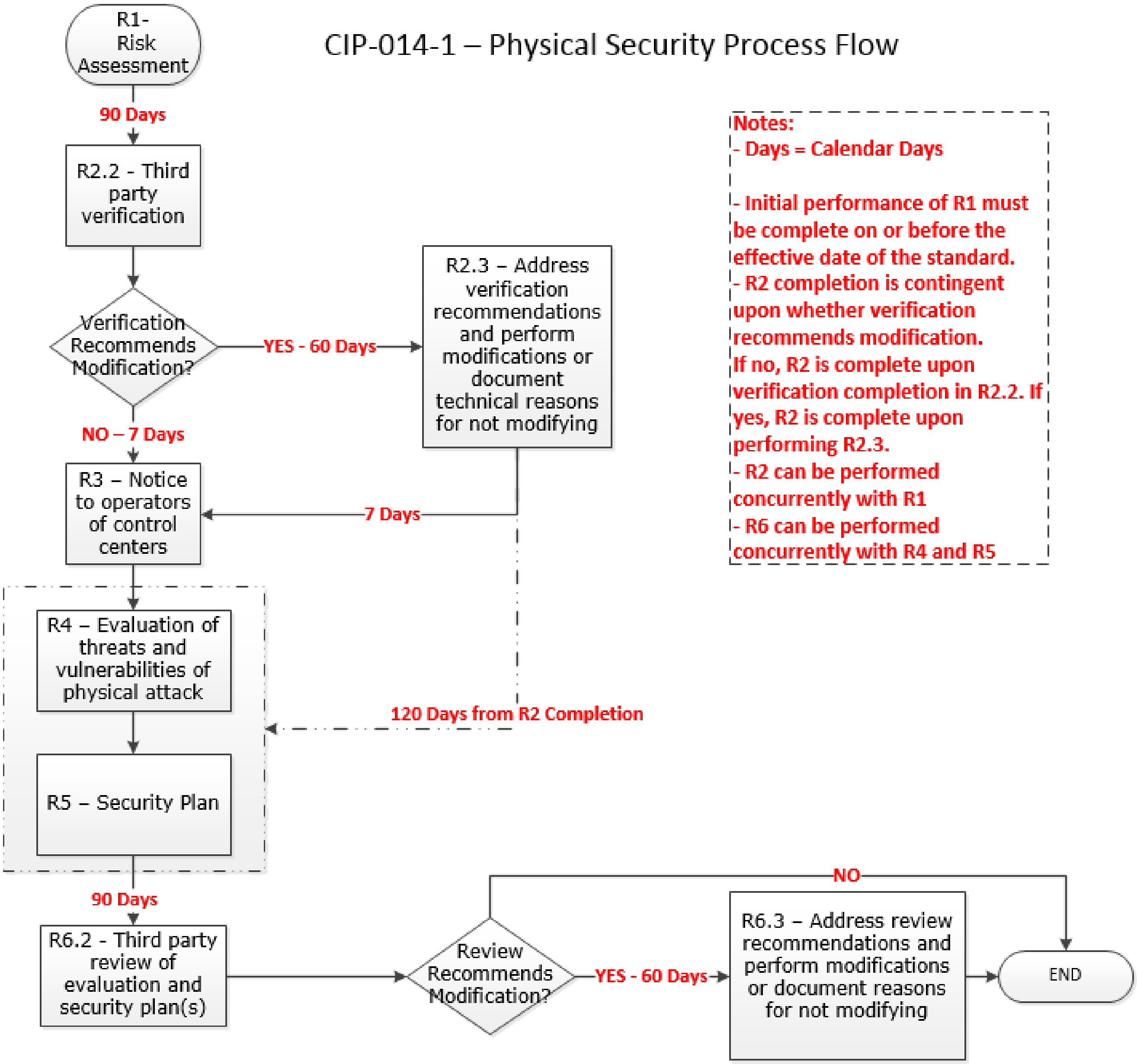
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that “only an instability that has a “critical impact on the operation of the interconnection” warrants finding that the facility causing the instability is critical under Requirement R1.” The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18 - 10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Physical Security
2. **Number:** CIP-014-3
3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the ~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events ~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. **Effective Dates: See Implementation Plan**

~~See Implementation Plan for CIP-014-32.~~

6. **Background:**

Reliability Standard CIP-014-~~2~~3 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove "widespread".	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	
3	TBD	Adopted by the NERC Board of Trustees	

Guidelines and Technical Basis

Section 4 Applicability

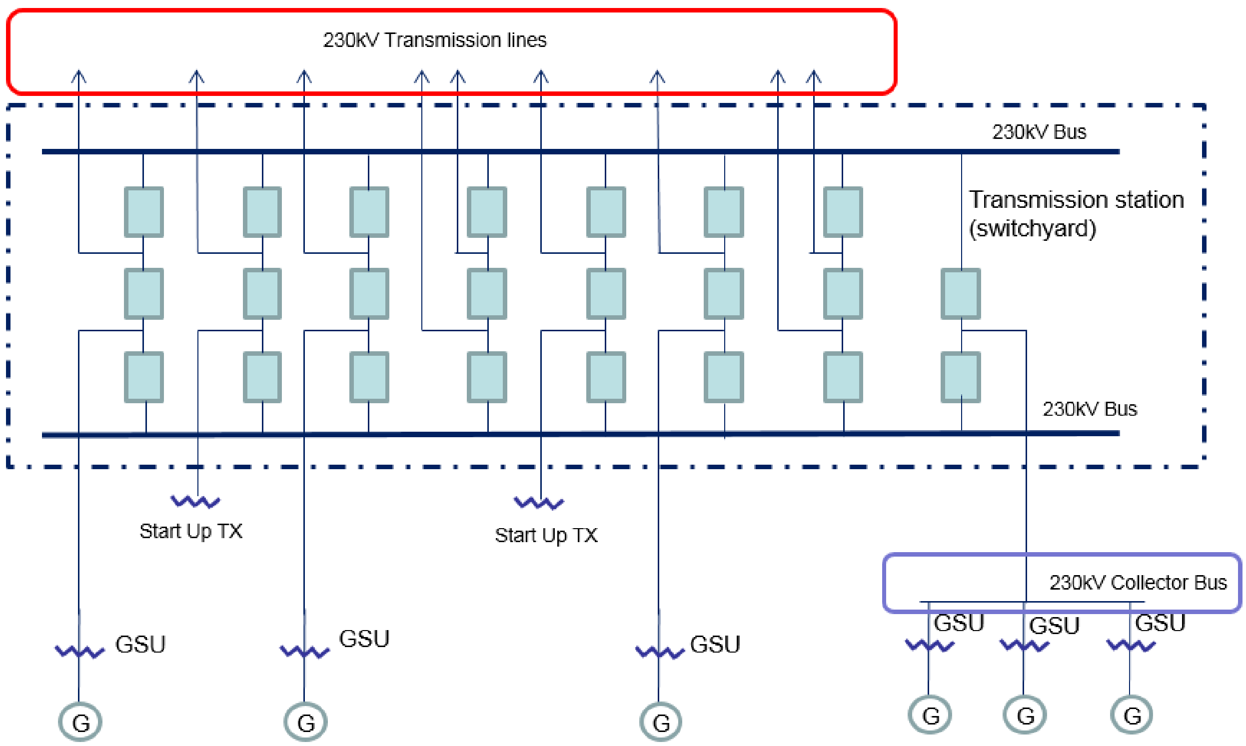
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security

(*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in ~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~instability, Cascading~~uncontrolled separation~~, or uncontrolled separation ~~Cascading~~that adversely impact the reliability of the Bulk Electric System for planning events. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g.

imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or

Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the

Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.

2. Only “need to know” employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

  Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

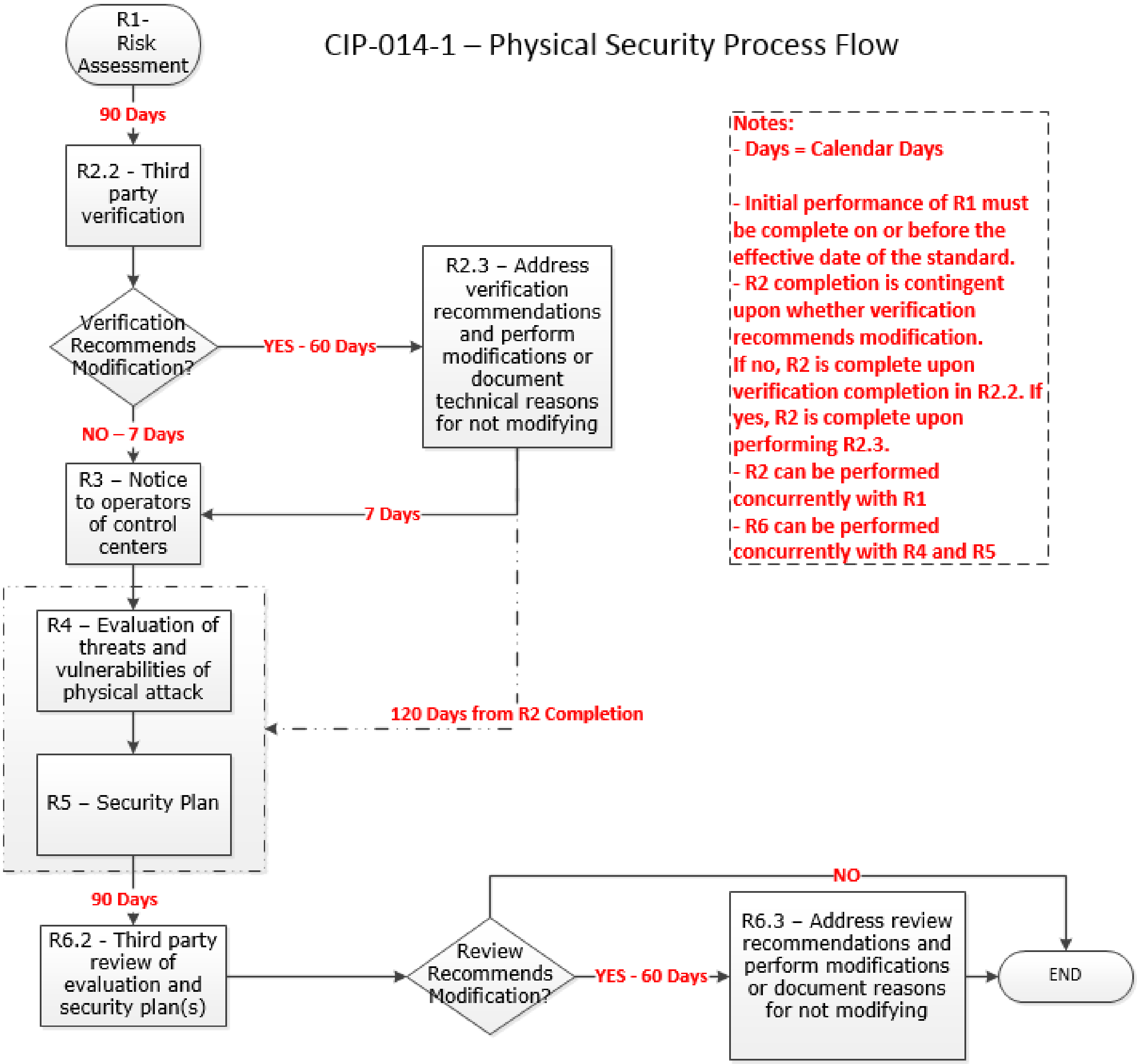
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
NO
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term “unaffiliated” means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term “unaffiliated” is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility’s location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-5
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system <u>performance result or outcome</u>?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that <u>reduces a stated risk</u> to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have <u>what capability</u>, to achieve what particular result or*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

M2. [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this Reliability Standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

(as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ,from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event , blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and encroachment into the MVCD as identified in FAC-003-5-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2. Reserved for				•

future use				
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned

				vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to “conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing.”[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from “Medium” to “High.”	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	TBD	Approved by Board of Trustees	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

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[15] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[16]Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[17] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1:
R1 is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines R1 requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirements R1 states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable

Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

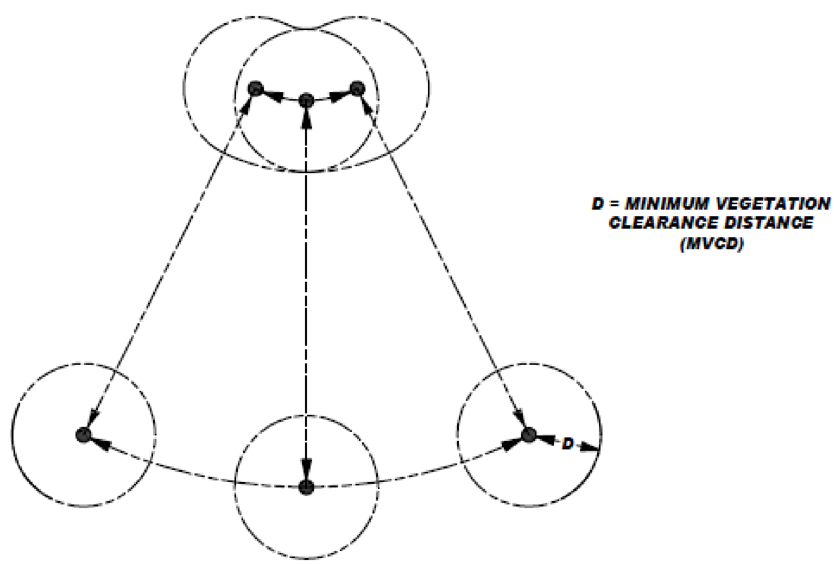

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner’s ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces

the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-5
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. **Effective Date:** See Implementation Plan

6. **Background:** This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

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[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

> *conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

~~**2.0.**~~

~~**M3.**~~**M2.** [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

~~M4.~~M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

~~M5.~~M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

~~M6.~~M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

~~M7.~~M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

~~M8.~~M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, ~~R2,~~ R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote ~~2~~4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only),~~ as a Facilit~~y~~ies that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as Facility~~ies~~ that if lost or degraded are ~~epected~~expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its~~

~~Transfer Capability Assessment (Planning Coordinator only)~~ as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and encroachment into the MVCD as identified in FAC-003-5-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2. Reserved for				•

future use				
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned

				vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to “conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing.”[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from “Medium” to “High.”	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	TBD	Approved by Board of Trustees	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

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15 The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

16 Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

17 The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV-, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:

The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:

In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1:
R1 is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines R1 requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirements R1 states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*

3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

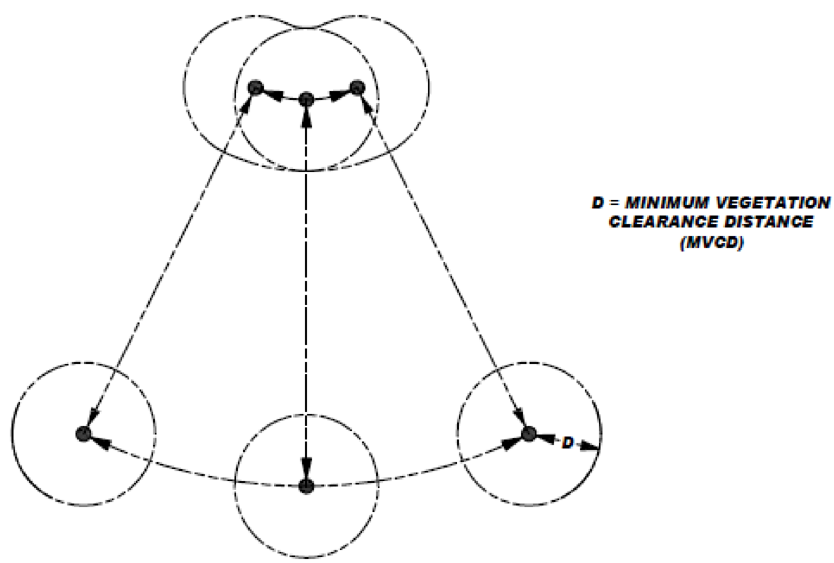

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal

rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
2. **Number:** FAC-013-3
3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.
4. **Applicability:**
   4.1. Planning Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessments.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. Reserved for Future use

M3. Reserved for Future use

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R4, R5 and R6 for the most recent assessment.

- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

<table>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td><td>The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology:
Part 1.1
Part 1.3
Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology:
Part 1.1
Part 1.3
Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.</td><td>The Planning Coordinator did not have a Transfer Capability methodology.
OR
The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology:
Part 1.1
Part 1.3
Part 1.5
OR
The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.</td></tr>
</table>

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. Reserved for future use				
R4.	The Planning Coordinator conducted a Transfer	The Planning Coordinator conducted a Transfer	The Planning Coordinator conducted a Transfer	The Planning Coordinator failed to conduct a Transfer

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Capability assessment outside the calendar year, but not by more than 30 calendar days.	Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5, but not more than 60 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
3	TBD	Approved by Board of Trustees.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
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45-day formal comment period with initial ballot	08/27/18-10/17/18

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10-day final ballot	August 2020
NERC Board adoption	November 2020

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This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
2. **Number:** FAC-013-3
3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.
4. **Applicability:**
    4.1. Planning Coordinators
5. **Effective Date:** See Implementation Plan ~~for FAC-013-3.~~

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessments.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

~~M2.~~M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

~~R3.~~R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~3.1.~~2.1. Distribute to the following prior to the effectiveness of such revisions:

~~3.1.1.~~2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

~~3.1.2.~~2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

~~3.2.~~2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

~~M3.~~M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

~~R5.~~R3. Reserved for Future use ~~If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)~~

~~M4.~~M3. ~~Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)~~Reserved for Future use

~~R7.~~R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~M5.~~M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

~~R8.~~R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M6.~~M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

~~R9.~~R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~M7.~~M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements~~ R3,~~ R4, R5 and R6 for the most recent assessment. ~~(R3 retired-Retirement approved by FERC effective January 21, 2014.)~~
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
~~Complaints~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. ~~(Retirement approved by FERC effective~~Reserved for future use	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology~~	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology~~	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology~~	~~The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~January 21, 2013.)~~	~~as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.~~	~~as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.~~	~~as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.~~	~~as required in Requirement R3 by more than 90 calendar days after receipt of the concern.~~ ~~OR~~ ~~The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.~~
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented	The Planning Coordinator made its Transfer	The Planning Coordinator made its Transfer	The Planning Coordinator failed to make its

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5, but not more than 60 calendar days after completion of the assessment.	Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	days after the receipt of the request for data.	days after the receipt of the request for data.	days after the receipt of the request for data.	The Planning Coordinator failed to provide the requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

None.~~Link to the Implementation Plan and other important associated documents.~~

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
3	TBD	Approved by Board of Trustees.	

~~Rationale~~

~~**During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board adoption, the text from the rationale text boxes was moved to this section.**~~

~~**Rationale for R1:**~~
~~**Text, text, text**~~

~~**Rationale for R2:**~~
~~**Text, text, text**~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
Eastern Interconnection	<59.75 Hz	>61.0 Hz
Western Interconnection	<59.55 Hz	>61.0 Hz
ERCOT Interconnection	<59.35 Hz	>61.0 Hz
Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-3 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

<u>Recording of Electrical Quantities</u>
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

<u>Current Recordings</u>
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this

determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing

filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Date~~s~~:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~2~~3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~2~~3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
Eastern Interconnection	<59.75 Hz	>61.0 Hz
Western Interconnection	<59.55 Hz	>61.0 Hz
ERCOT Interconnection	<59.35 Hz	>61.0 Hz
Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-~~2~~3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a -10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-~~2~~ 3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-~~2~~ 3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-~~2~~ 3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-~~2~~ 3 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

<u>Recording of Electrical Quantities</u>
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

<u>Current Recordings</u>
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this

determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-~~2~~ 3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing

filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-5
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below

unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the

Requirement	Lower	Moderate	High	Severe
				loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line

Requirement	Lower	Moderate	High	Severe
				relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR

Requirement	Lower	Moderate	High	Severe
		months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning	more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process

Requirement	Lower	Moderate	High	Severe
		Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)		described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR

Requirement	Lower	Moderate	High	Severe
				The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

Version	Date	Action	Change Tracking
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	TBD	Adopted by the NERC Board of Trustees	

PRC-023-5 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-5 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

    i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

    ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

    iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-5
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation~~ Plan for the Revised Definition of "Remedial Action Scheme"~~.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below

unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the

Requirement	Lower	Moderate	High	Severe
				loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line

Requirement	Lower	Moderate	High	Severe
				relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR

Requirement	Lower	Moderate	High	Severe
		months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning	more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process

Requirement	Lower	Moderate	High	Severe
		Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)		described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR

Requirement	Lower	Moderate	High	Severe
				The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

Version	Date	Action	Change Tracking
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	TBD	Adopted by the NERC Board of Trustees	

PRC-023-~~4~~5 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-45 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

    i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

    ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

    iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. **Effective Dates: See Implementation Plan**

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Planning Horizon for a planning event, that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Planning Horizon for a planning event.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, “Becoming Aware of an Element That Tripped in Response to a Power Swing.”

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, “Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis.”

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

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Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	TBD	Adopted by NERC Board of Trustees	

PRC-026-2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
    - At least 120 degrees, or
    - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: [http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)](http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-2 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-2 – Attachment B.

[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20 20/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay’s susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R}=\frac{0.85}{1.15}=0.739$$ Eq. (5): $$\frac{E_S}{E_R}=\frac{1.15}{0.85}=1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

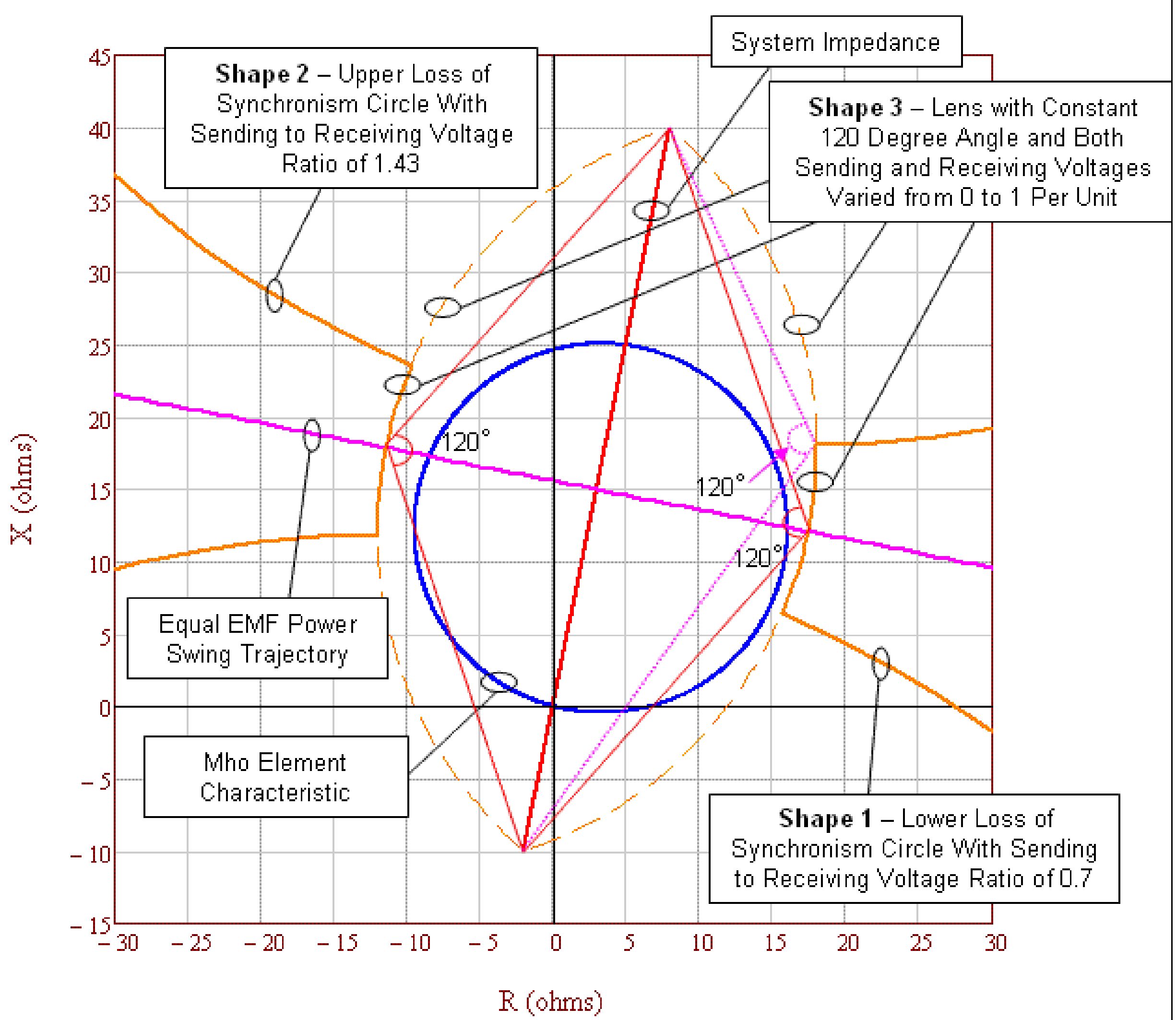


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-2 – Attachment B, Criterion A, No. 1.

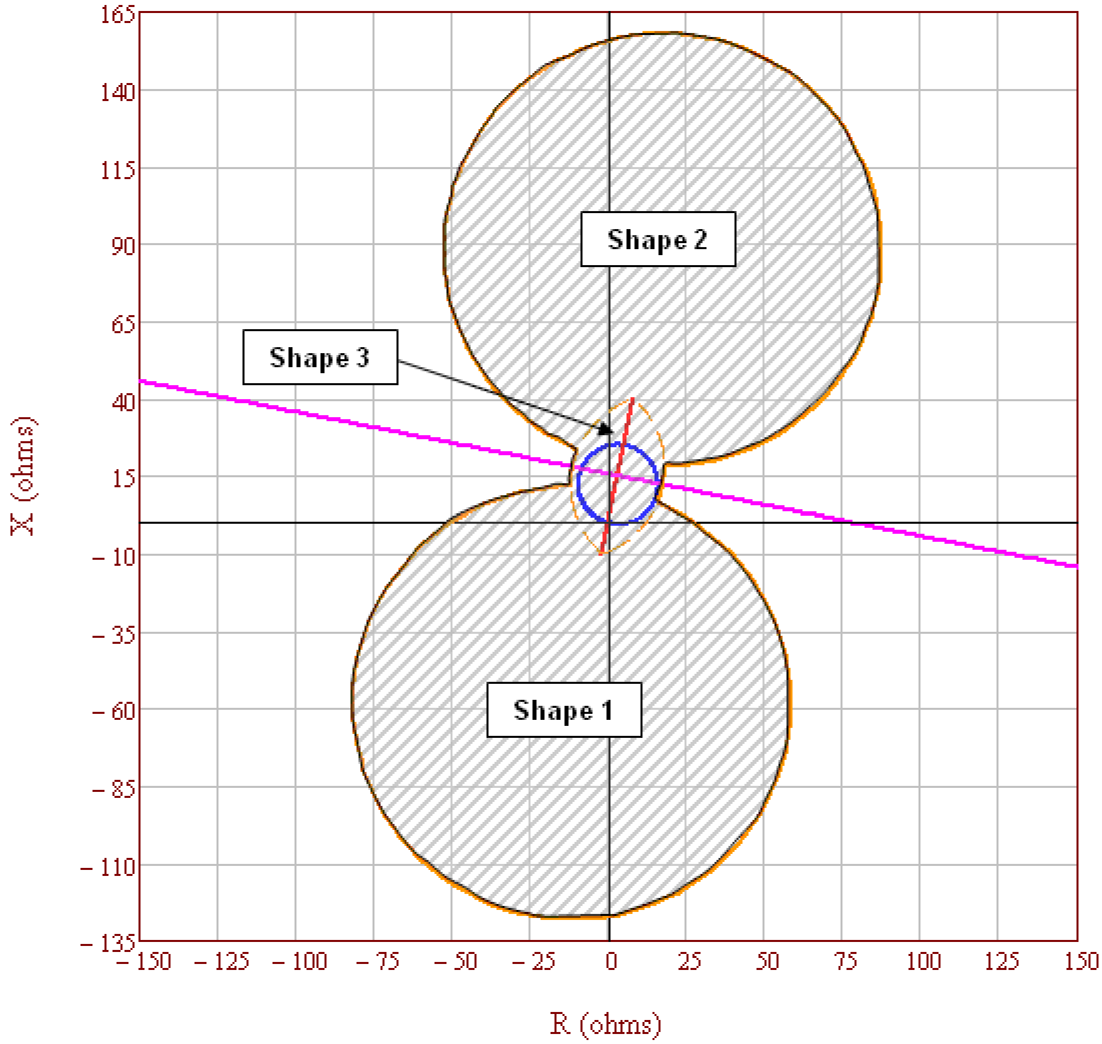


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-026-2 – Attachment B, Criterion A, No.1.

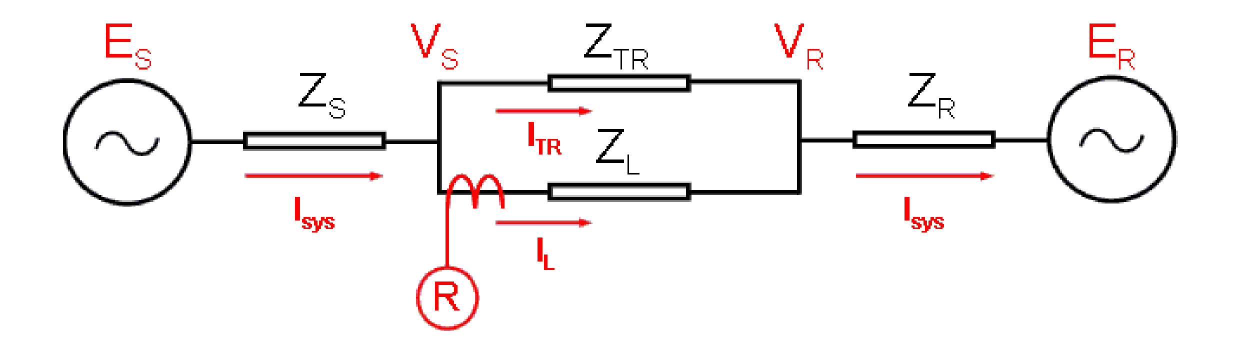


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

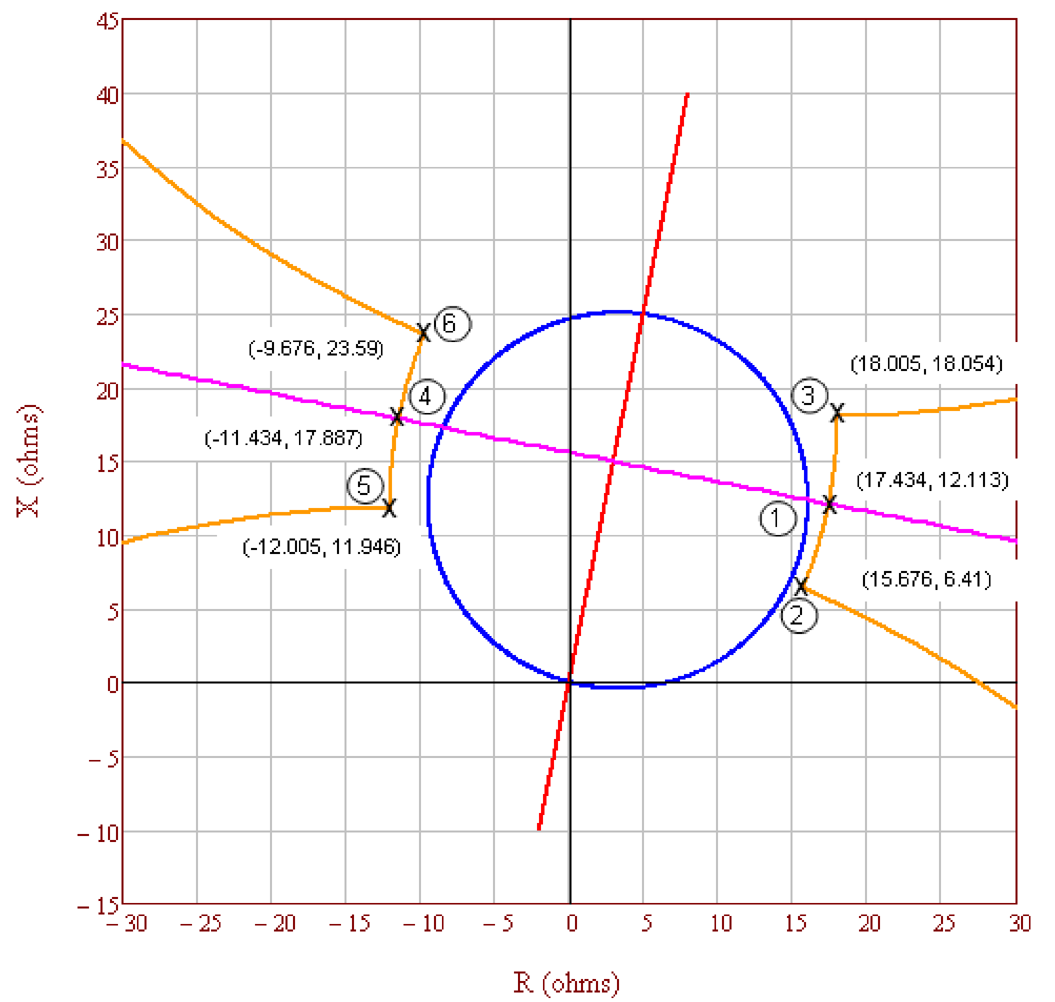


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \dfrac{230{,}000\angle 120°\,V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\,V$		
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\,V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\,V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\,\Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4+j20)\,\Omega \times (4+j20) \times 10^{10}\,\Omega\right)}{\left((4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega\right)}$		
	$Z_{total} = 4 + j20\,\Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2+j10)\,\Omega + (4+j20)\,\Omega + (4+j20)\,\Omega$		
	$Z_{sys} = 10 + j50\,\Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\,V - 132{,}791\angle 0°\,V}{(10 + j50\,)\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\,A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4+j20)\times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\big((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\big)}{\big((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\big)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

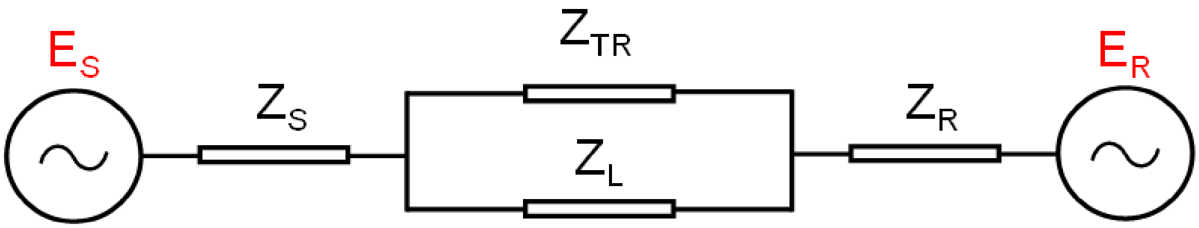
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\,V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1°\,A]$
	$V_S = 95{,}756\angle - 106.1°\,V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle - 106.1°\,V}{4{,}511\angle 131.1°\,A}$
	$Z_{L-Relay} = -11.434 + j17.887\,\Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 240°\,V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\,V$		
Eq. (39)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\,V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\,V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\,\Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\,\Omega \times (4+j20) \times 10^{10}\,\Omega\right)}{\left((4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega\right)}$
	$Z_{total} = 4 + j20\,\Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\,\Omega) + (4 + j20\,\Omega) + (4 + j20\,\Omega)$
	$Z_{sys} = 10 + j50\,\Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\,V - 132{,}791\angle 0°\,V}{10 + j50\,\Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\,A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\,A \times \frac{(4+j20) \times 10^{10}\,\Omega}{(4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega}$
	$I_L = 3{,}854\angle 125.5°\,A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\,V - [(2 + j10\,)\,\Omega \times 3{,}854\angle 125.5°\,A]$
	$V_S = 65{,}270.5\angle -99.4°\,V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\,V}{3{,}854\angle 125.5°\,A}$
	$Z_{L-Relay} = -12.005 + j11.946\,\Omega$

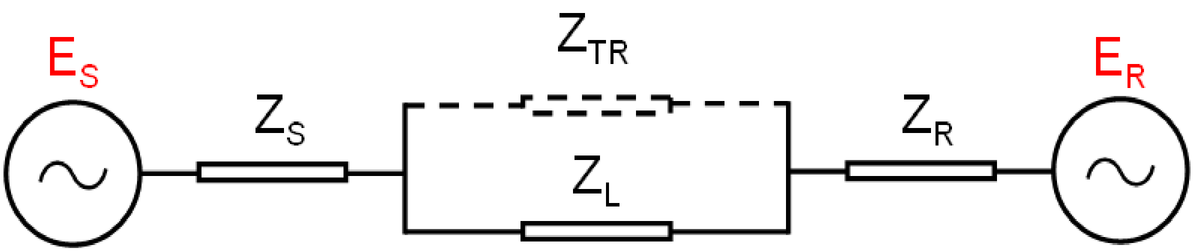
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1^\circ\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1^\circ\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240^\circ\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1^\circ\ A]$
	$V_S = 98{,}265\angle -110.6^\circ\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6^\circ\ V}{3{,}854\angle 137.1^\circ\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

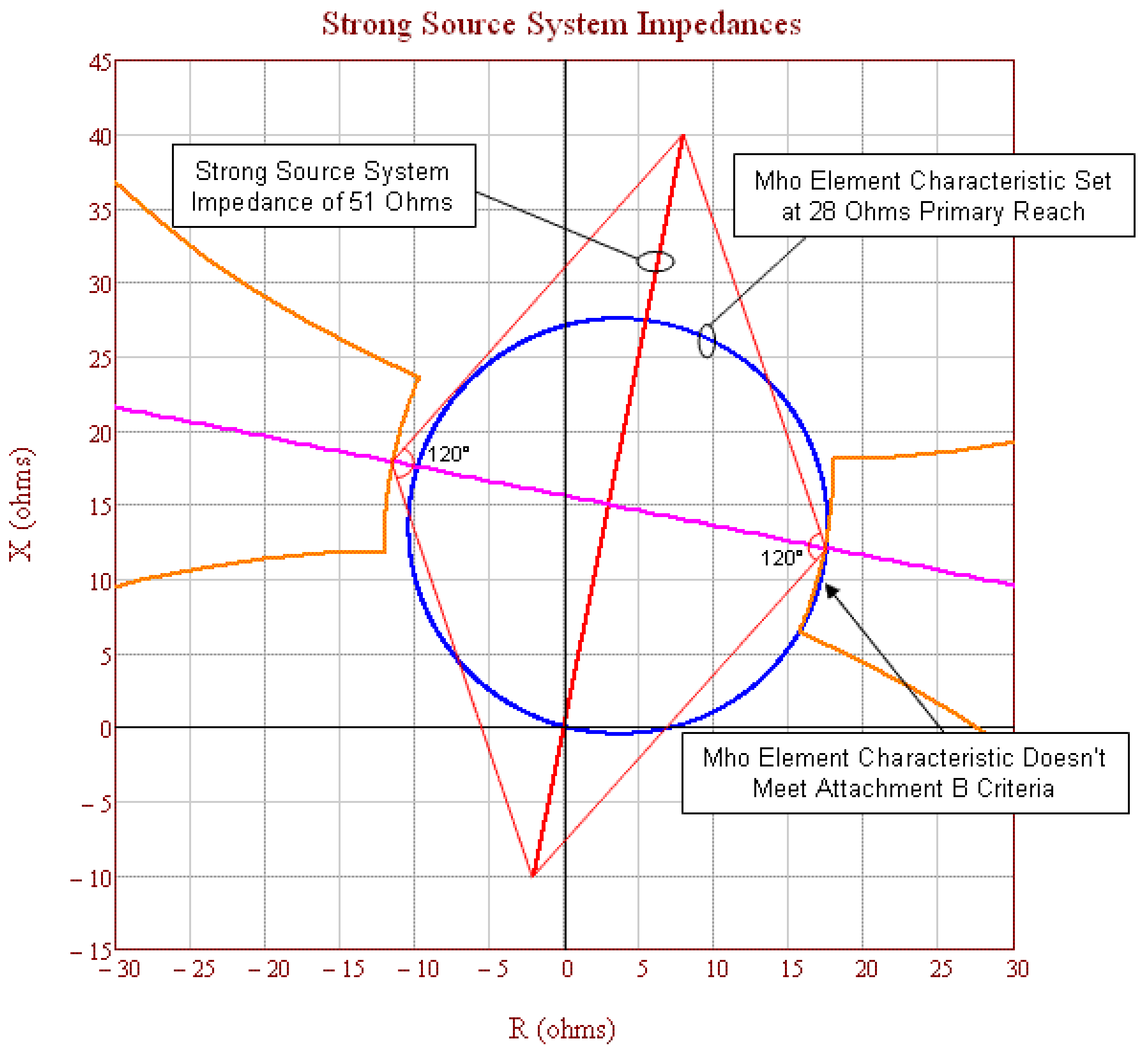


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

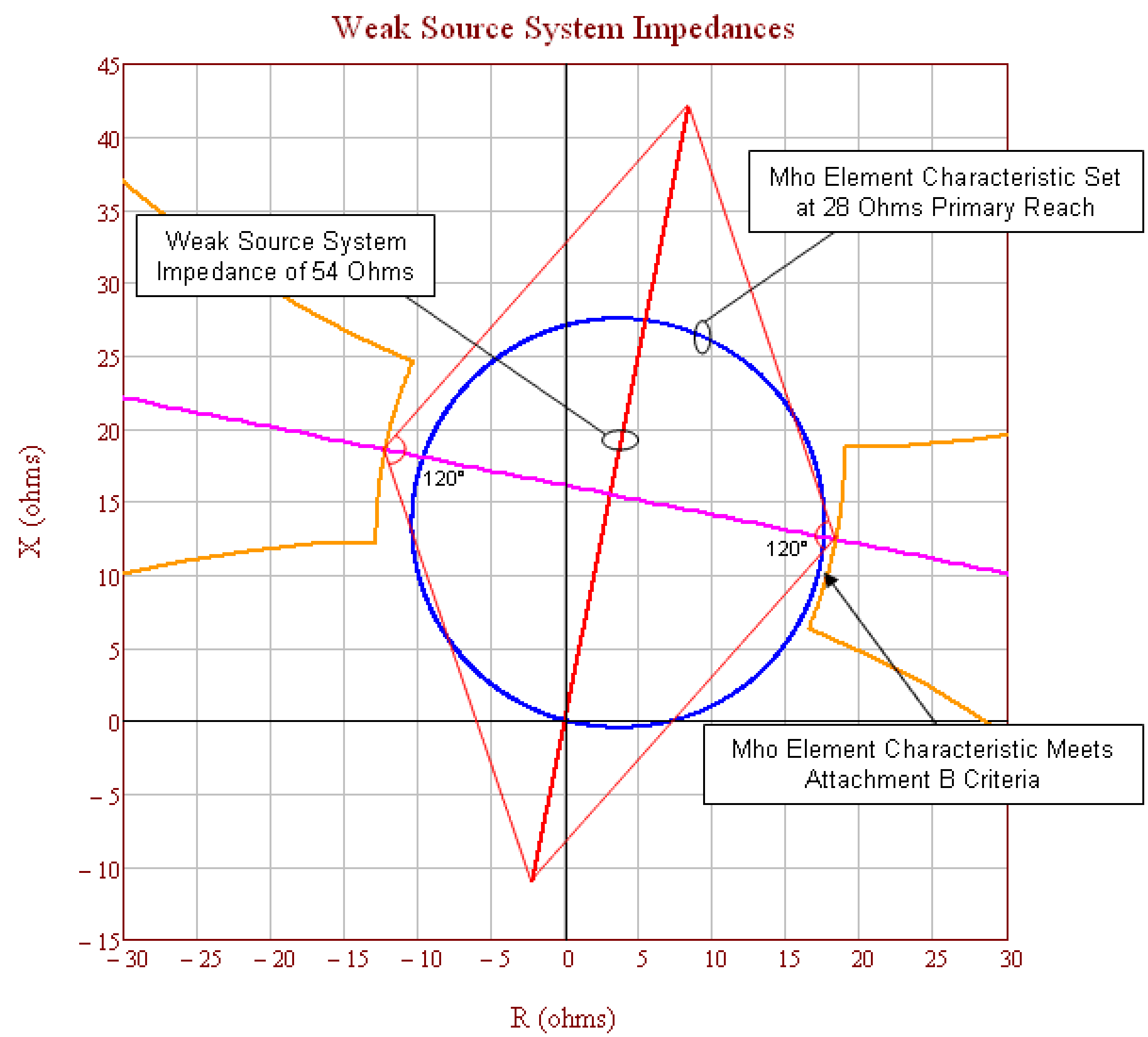


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

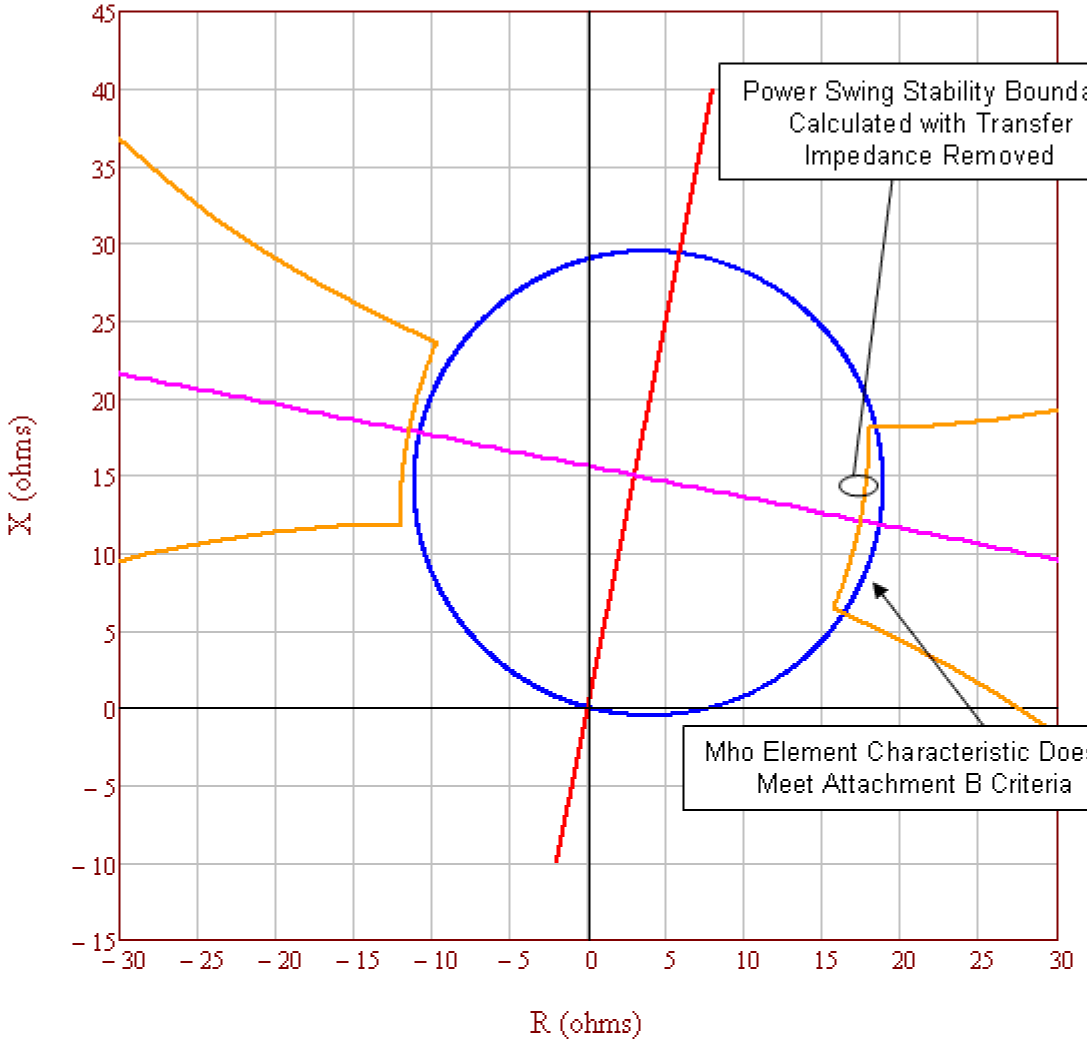


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

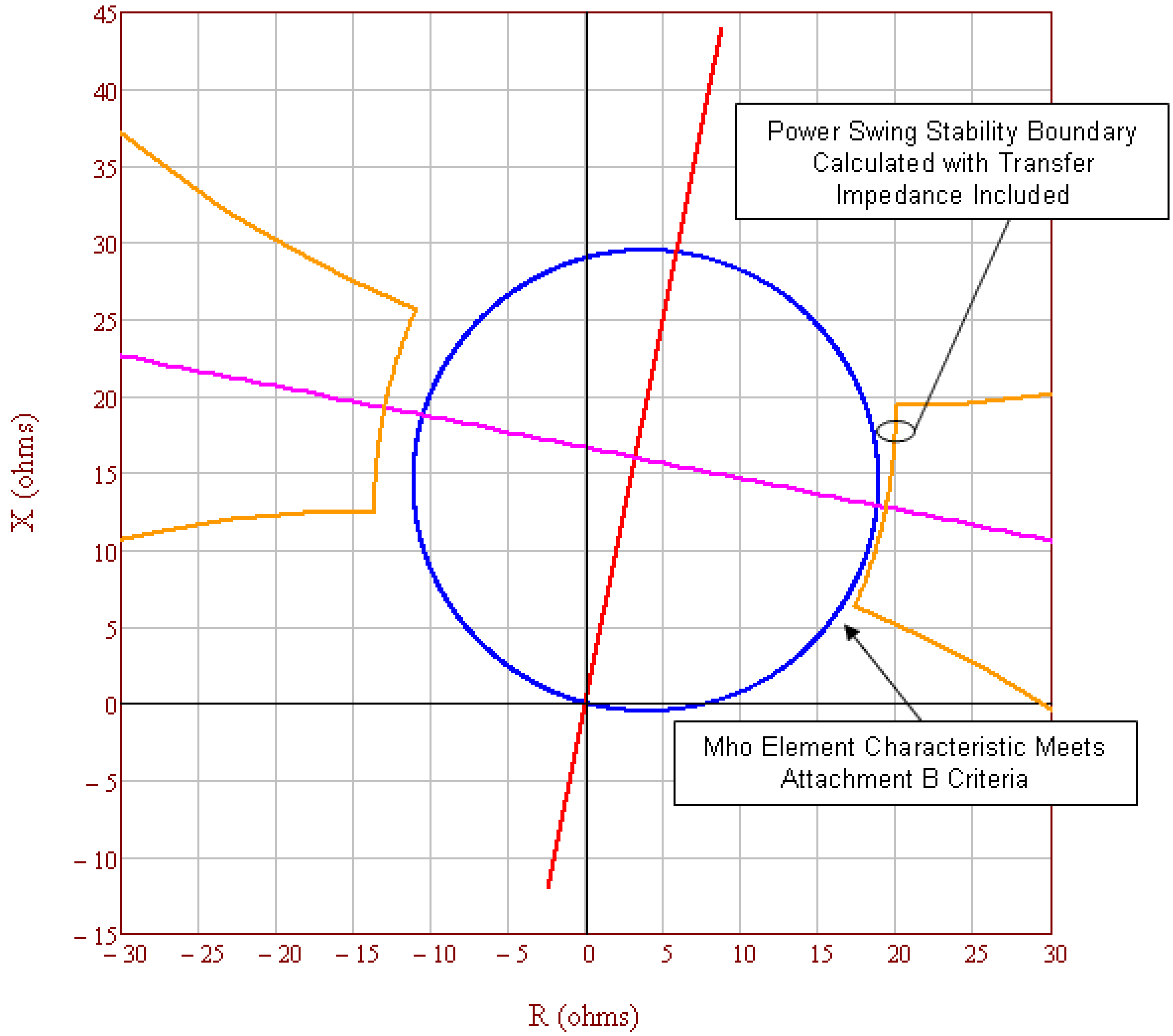


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

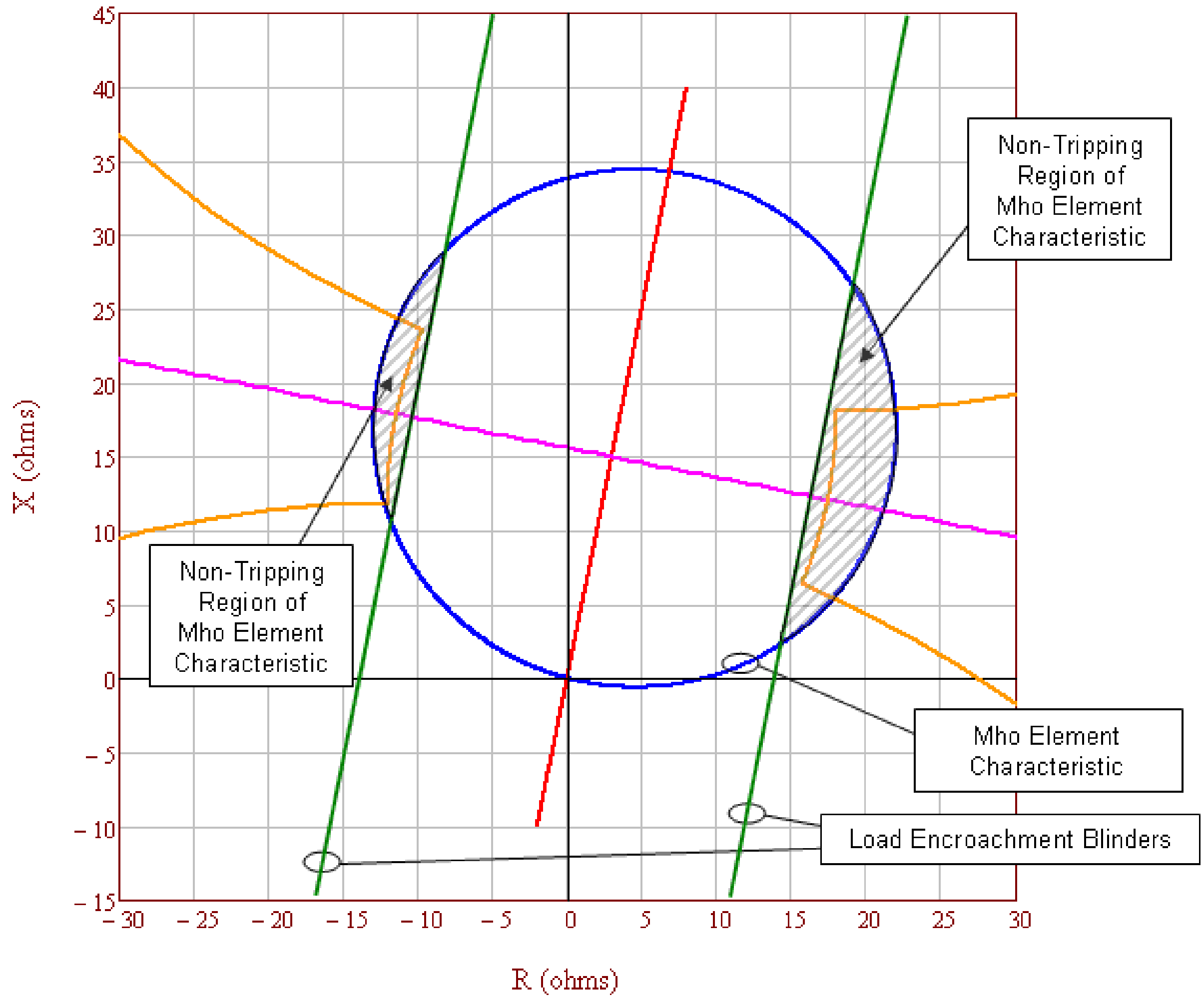


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-2– Attachment B, Criterion A.

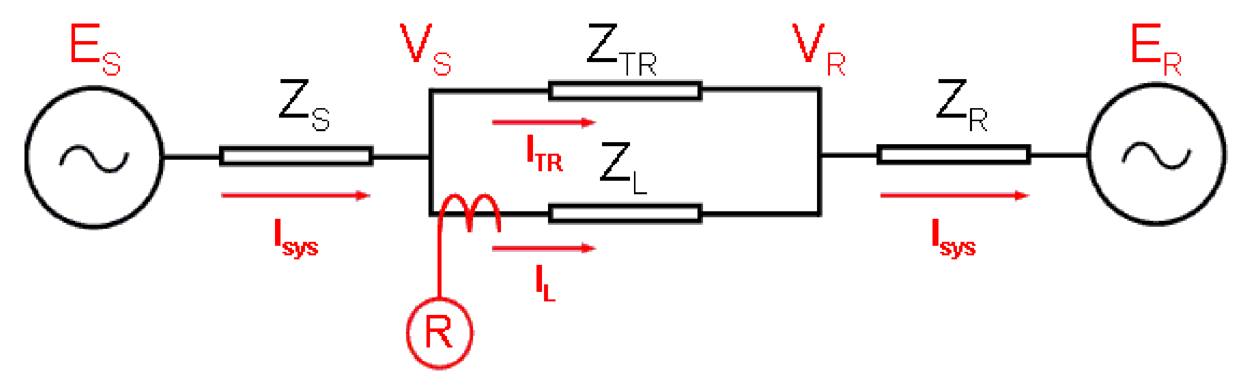


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)

The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.

Eq. (70)	$I_L = \dfrac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \dfrac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \dfrac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \dfrac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \dfrac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \dfrac{V_S}{I_L} = Z_L + Z_R + \dfrac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

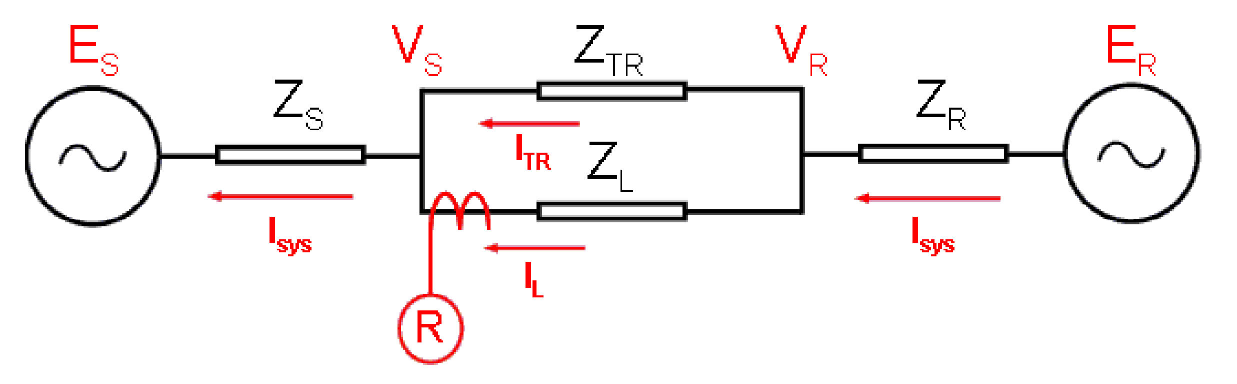


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

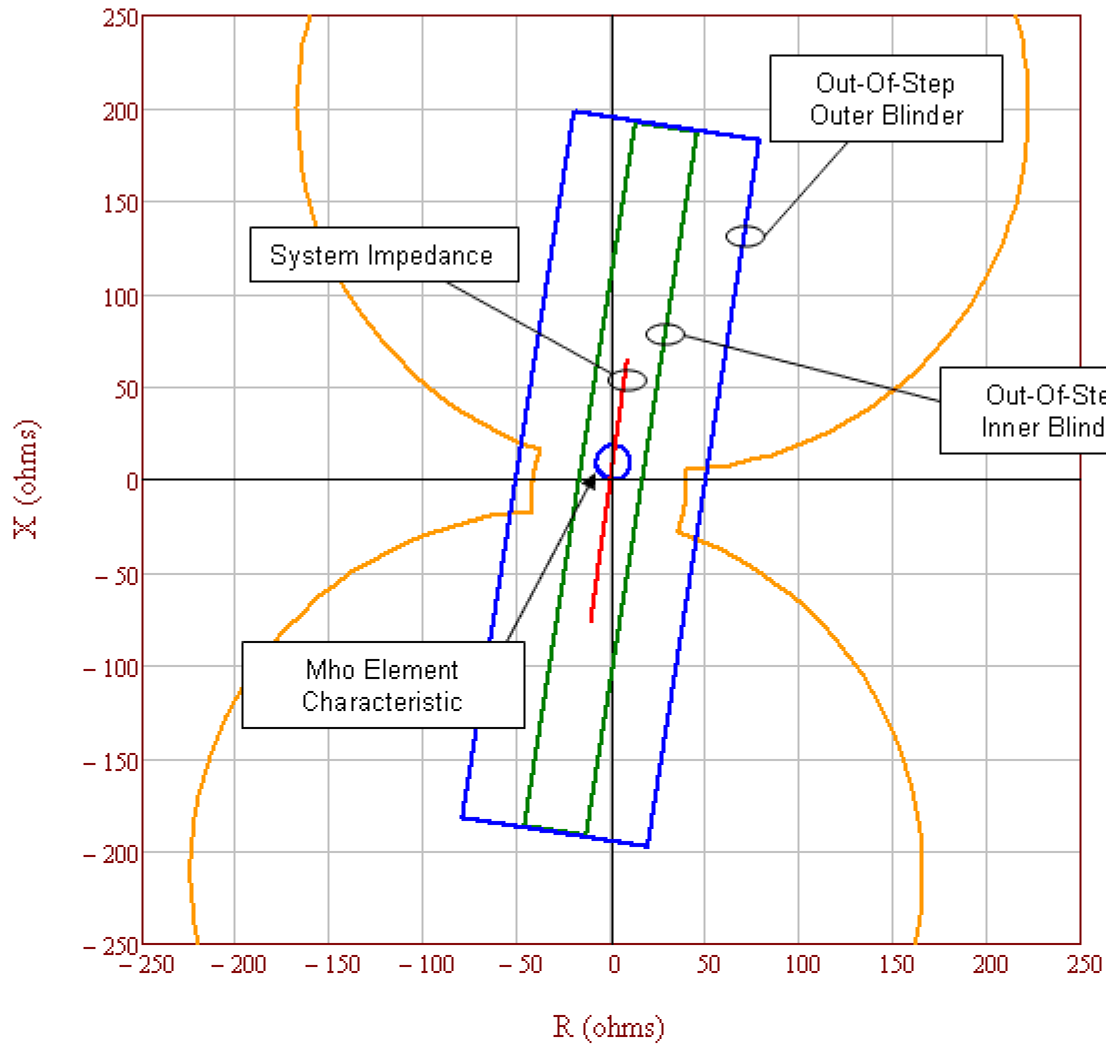


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)		
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.		
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.		
Given:	$E_S = 0.7$	$E_R = 1.0$
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$	
The total system impedance as seen by the relay with infeed formulae applied.		
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$; $Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$	
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$	
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$	
	$Z_{sys} = 10 + j50\ \Omega$	
The calculated coordinates of the lower loss-of-synchronism circle center.		
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$	
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$	
	$Z_{C1} = -11.608 - j58.039\ \Omega$	
The calculated radius of the lower loss-of-synchronism circle.		
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$	
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$	
	$r_a = 69.987\ \Omega$	
The calculated coordinates of the upper loss-of-synchronism circle center.		
Given:	$E_S = 1.0$	$E_R = 0.7$

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

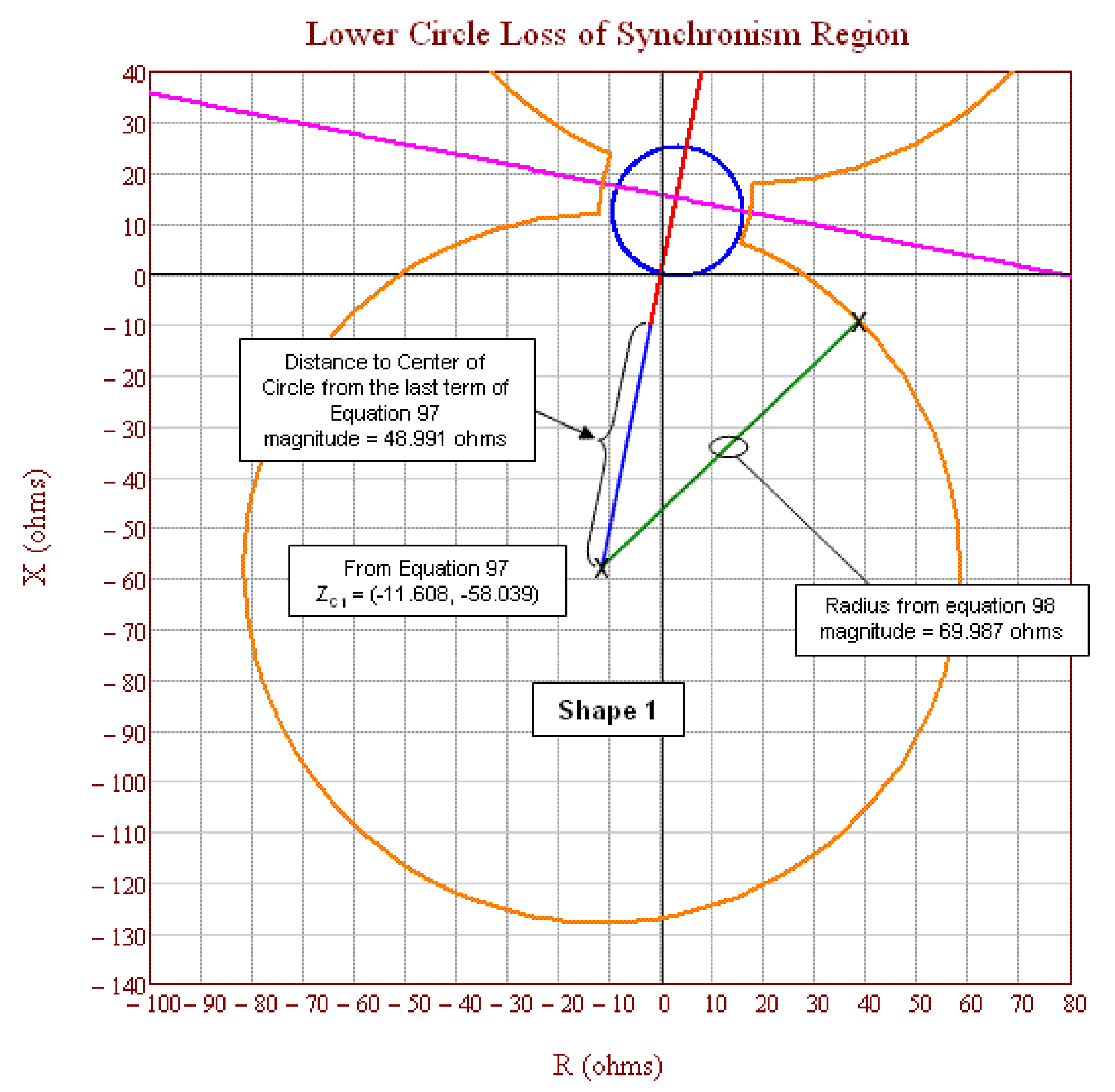


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

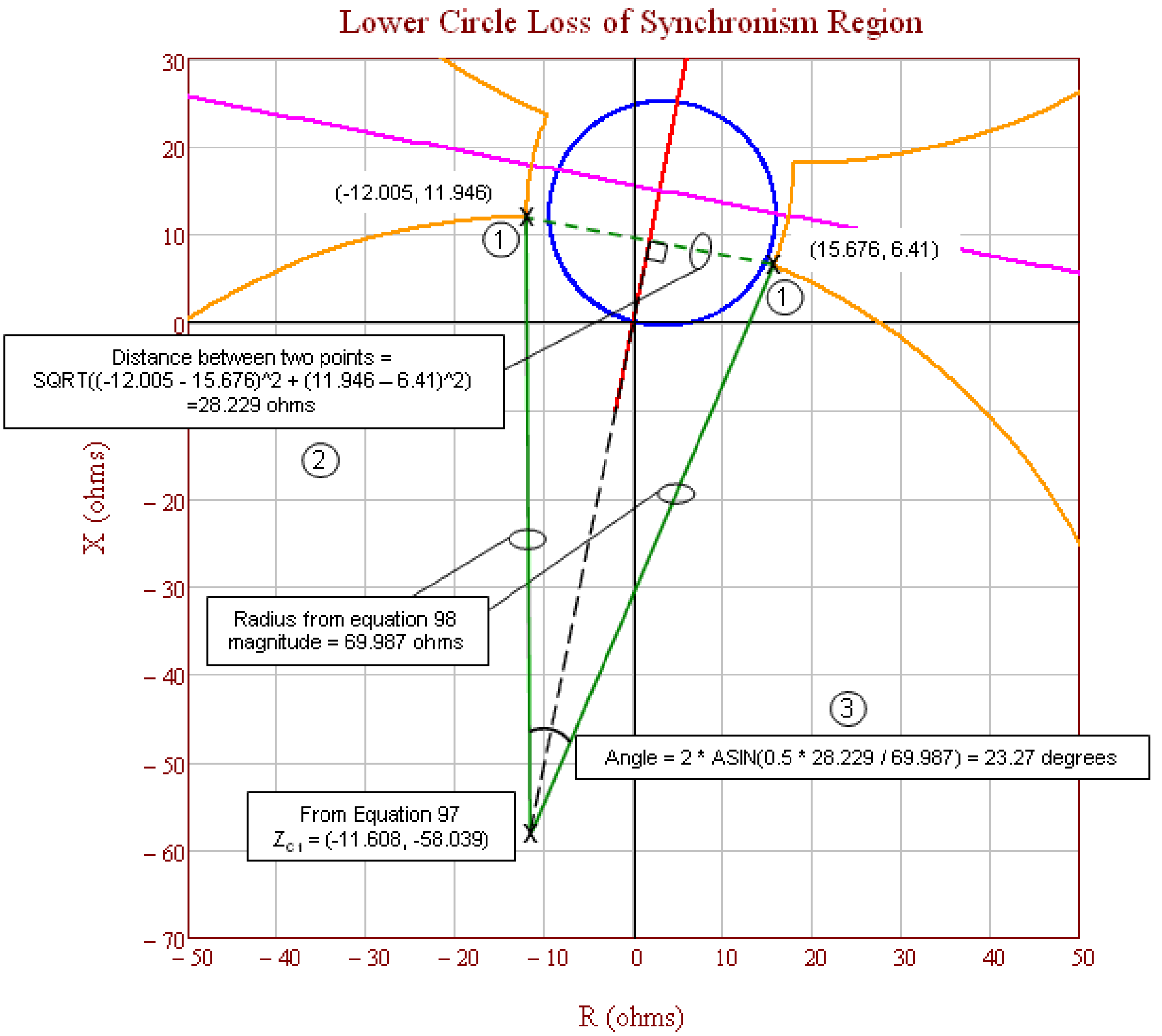


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

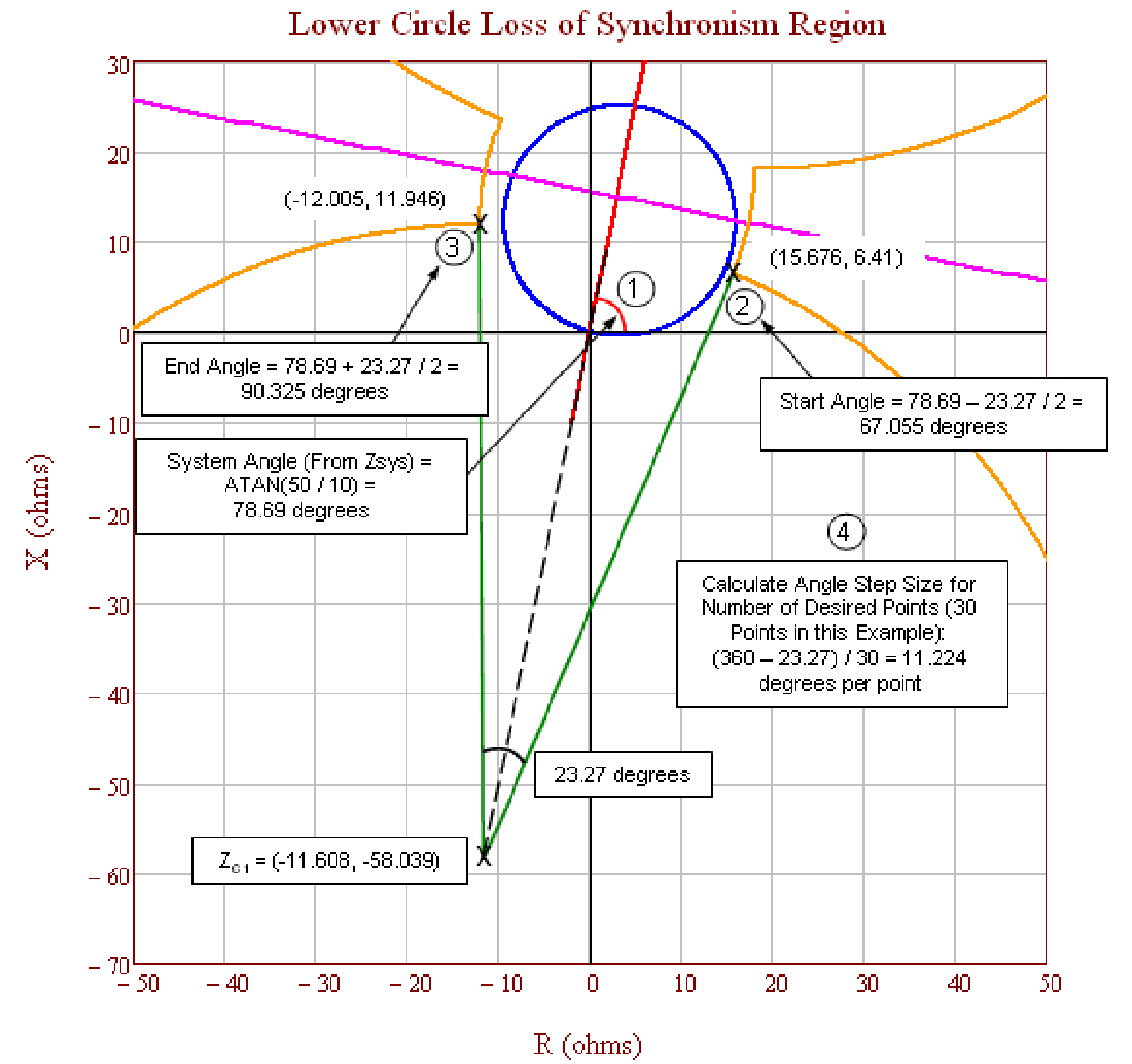


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

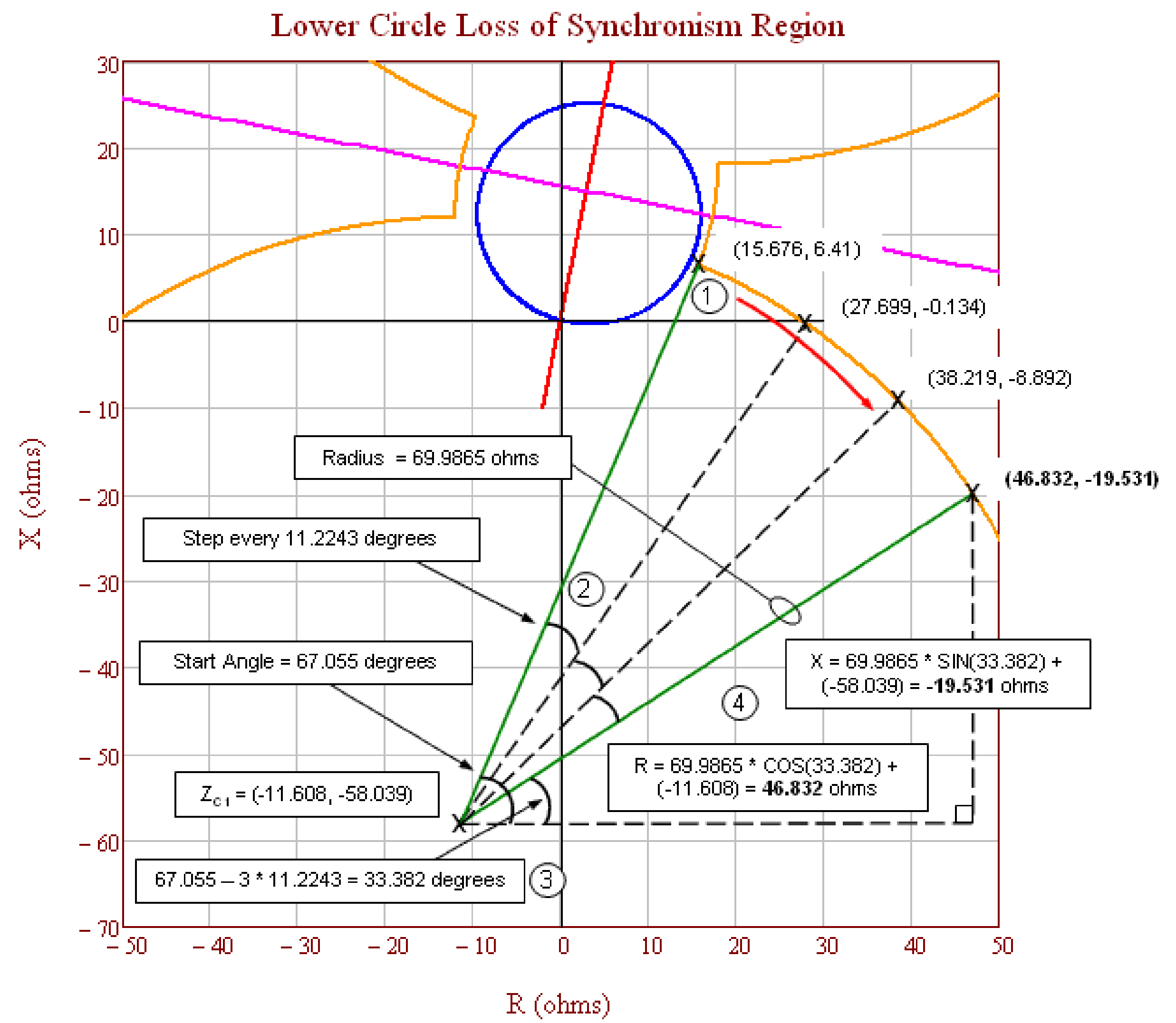


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

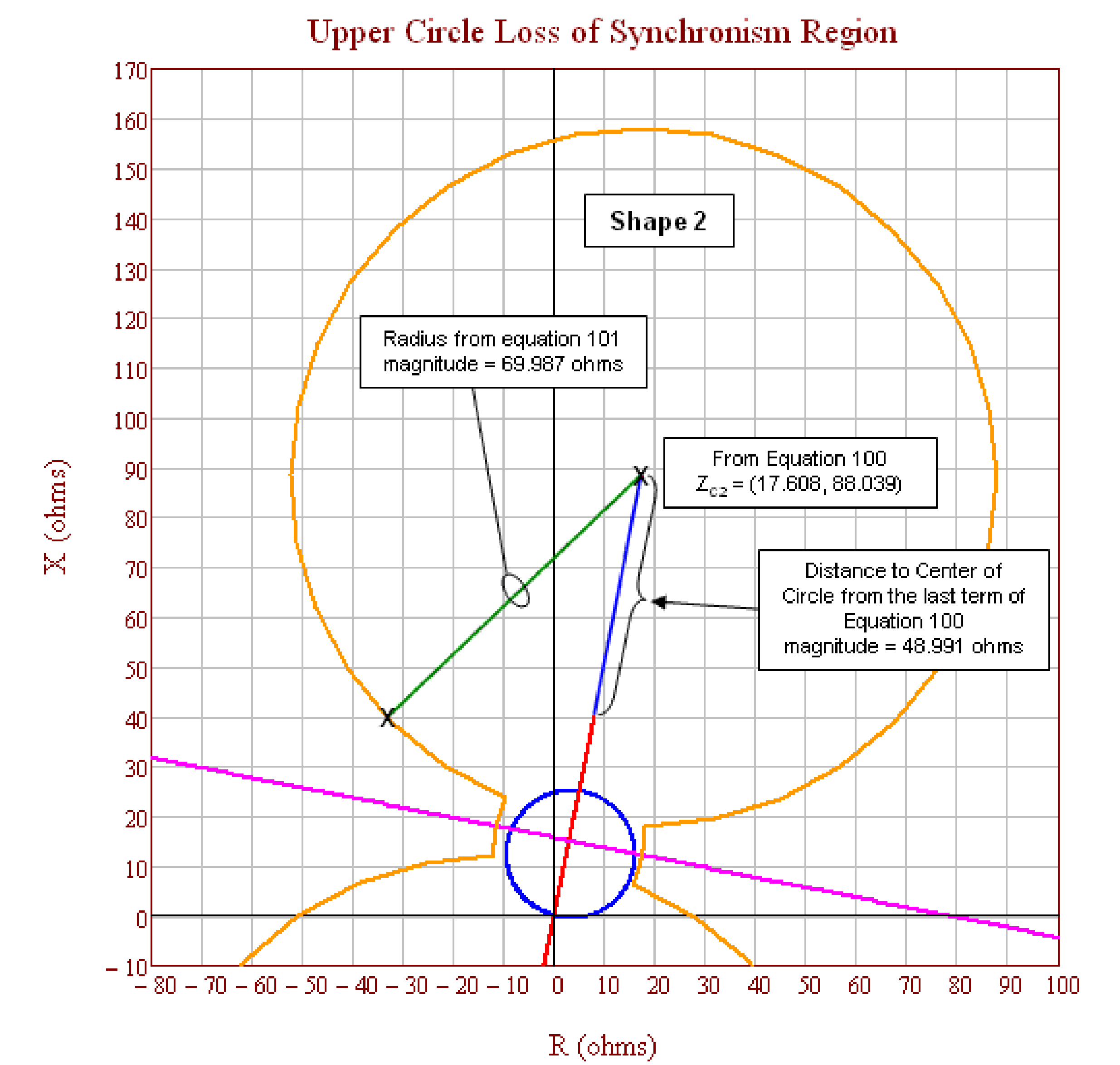


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

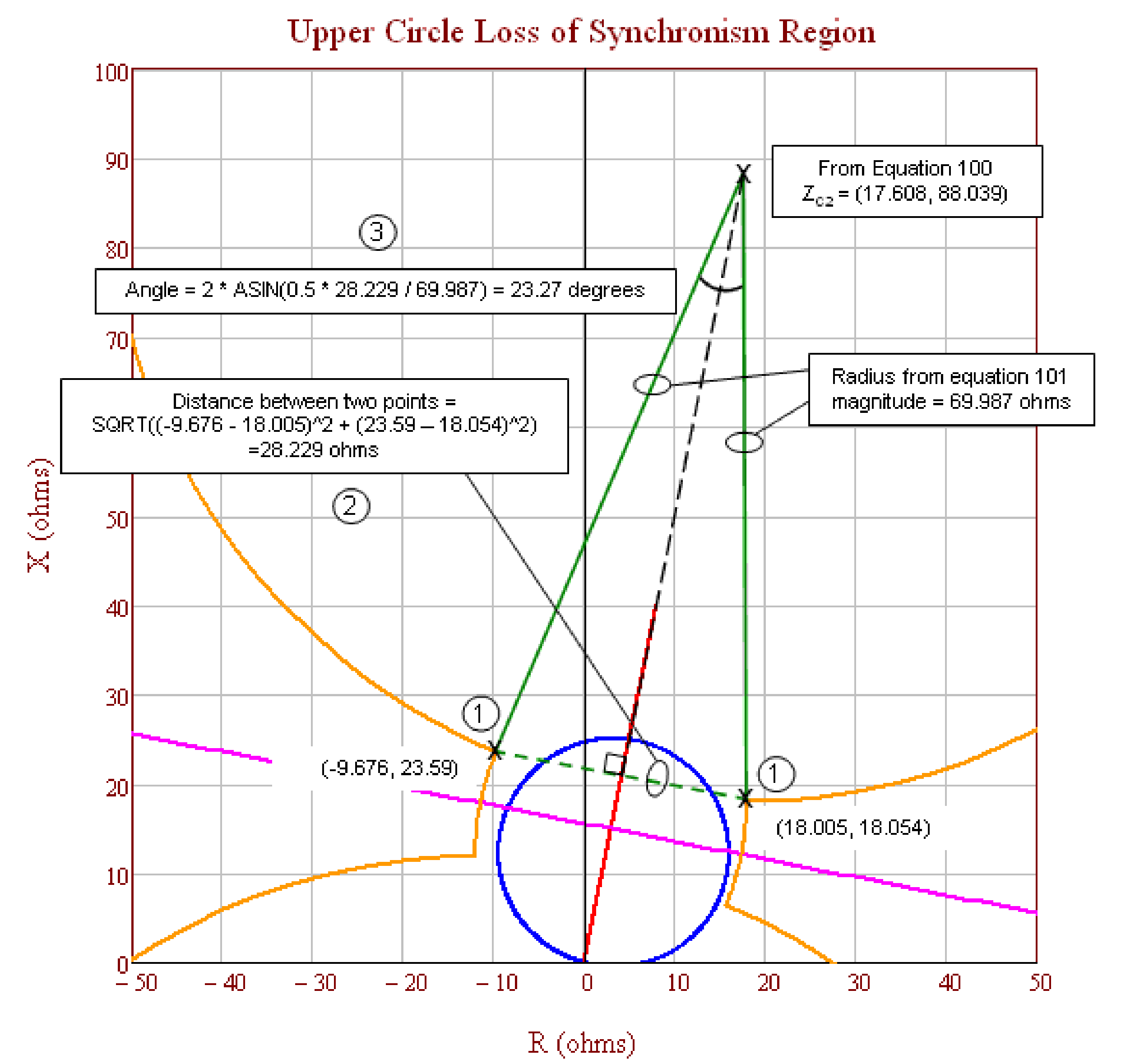


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

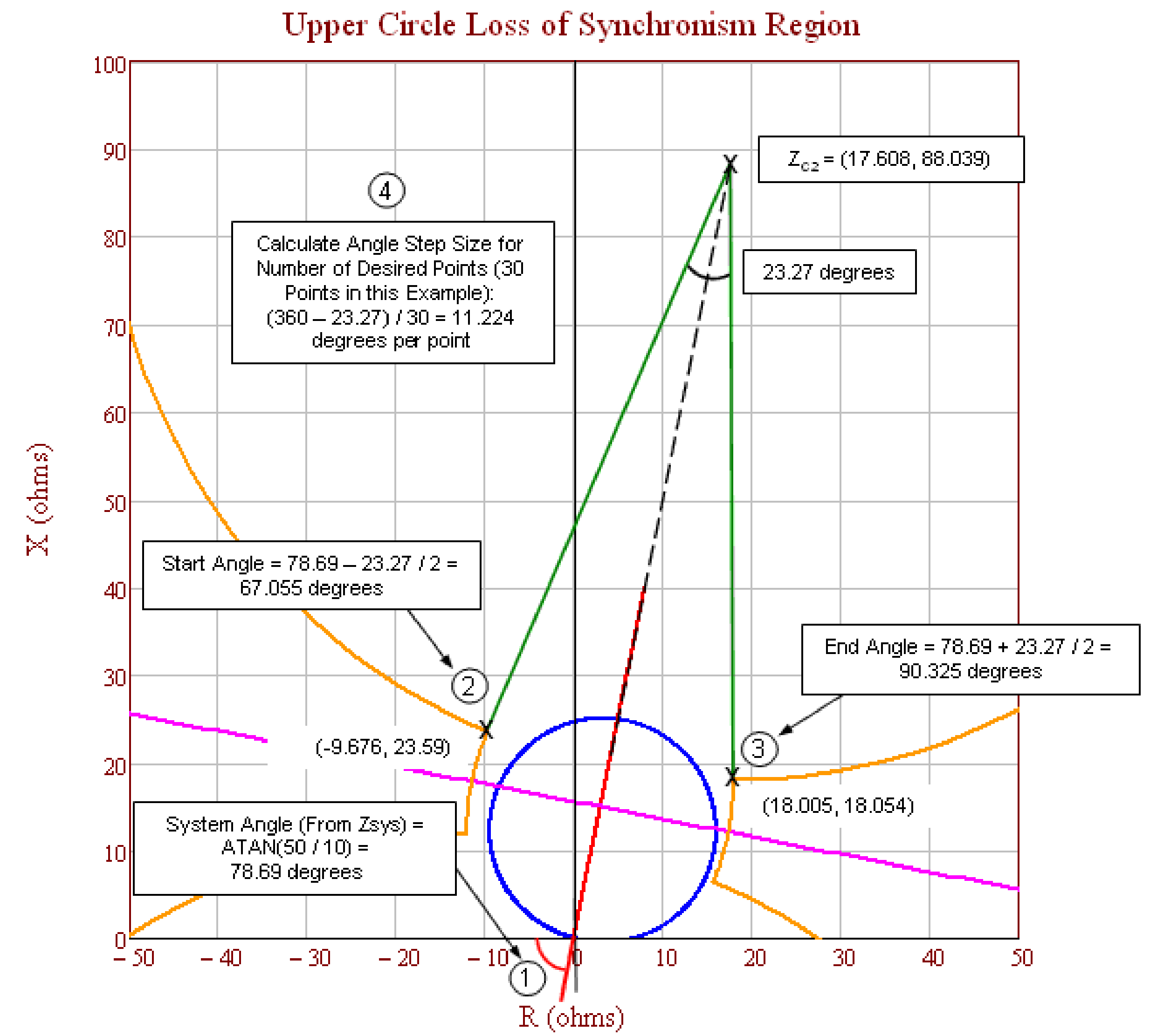


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

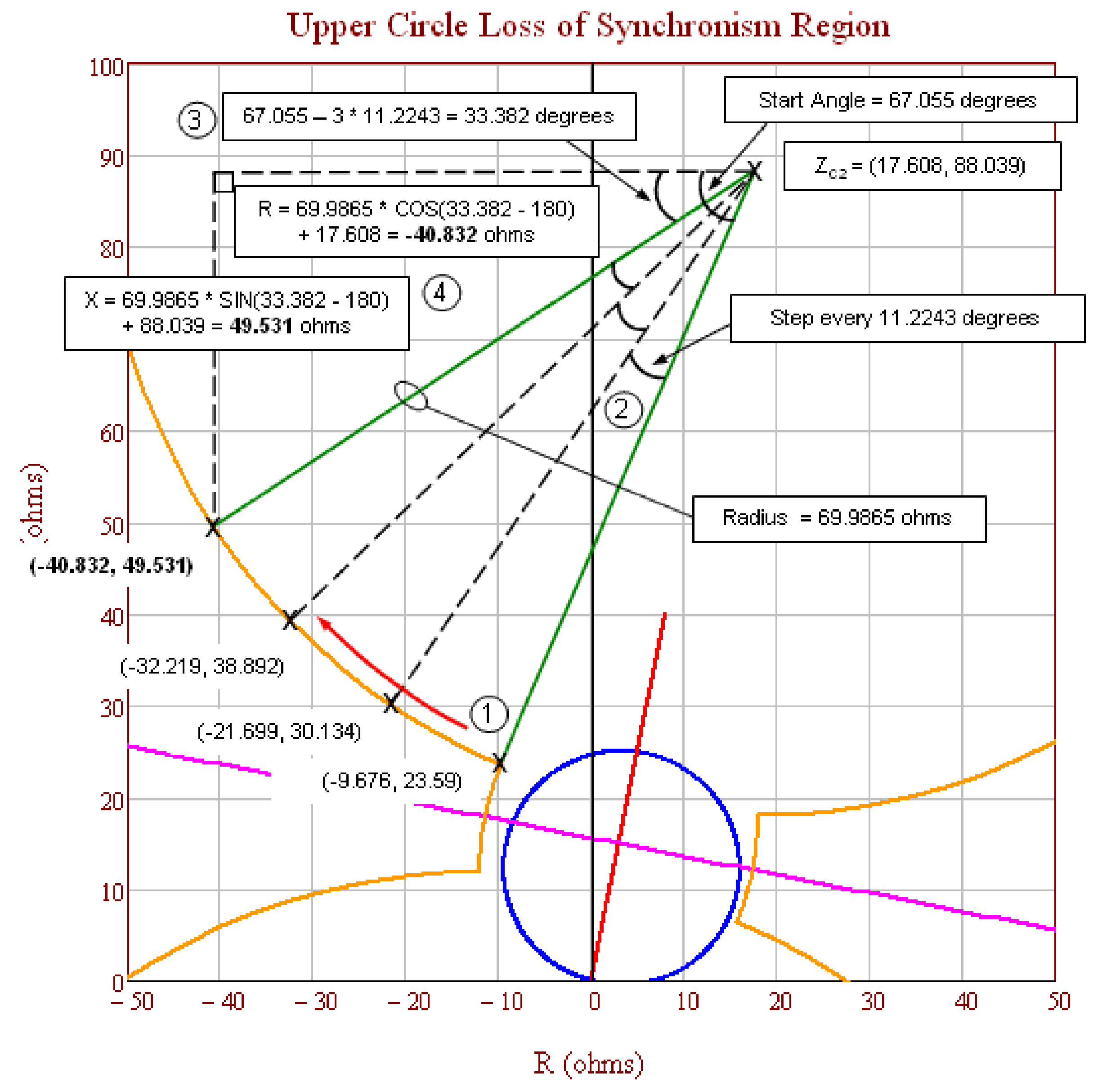


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

<table>
<tr><th colspan="4">Table 14: Example Calculation (Overcurrent)</th></tr>
<tr><td colspan="4">This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms.

Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-2 – Attachment B, Criterion B.</td></tr>
<tr><td>Eq. (102)</td><td colspan="3">$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_S = 139{,}430\angle 120°\ V$</td></tr>
<tr><td colspan="4">Receiving-end generator terminal voltage.</td></tr>
<tr><td>Eq. (103)</td><td colspan="3">$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_R = 139{,}430\angle 0°\ V$</td></tr>
<tr><td colspan="4">The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.</td></tr>
<tr><td>Given:</td><td>$Z_S = 3 + j26\ \Omega$</td><td>$Z_L = 1.3 + j8.7\ \Omega$</td><td>$Z_R = 0.3 + j7.3\ \Omega$</td></tr>
<tr><td>Eq. (104)</td><td colspan="3">$Z_{sys} = Z_S + Z_L + Z_R$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = 4.6 + j42\ \Omega$</td></tr>
<tr><td colspan="4">Total system current.</td></tr>
<tr><td>Eq. (105)</td><td colspan="3">$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$</td></tr>
<tr><td></td><td colspan="3">$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$</td></tr>
<tr><td></td><td colspan="3">$I_{sys} = 5{,}715.82\angle 66.25°\ A$</td></tr>
</table>

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

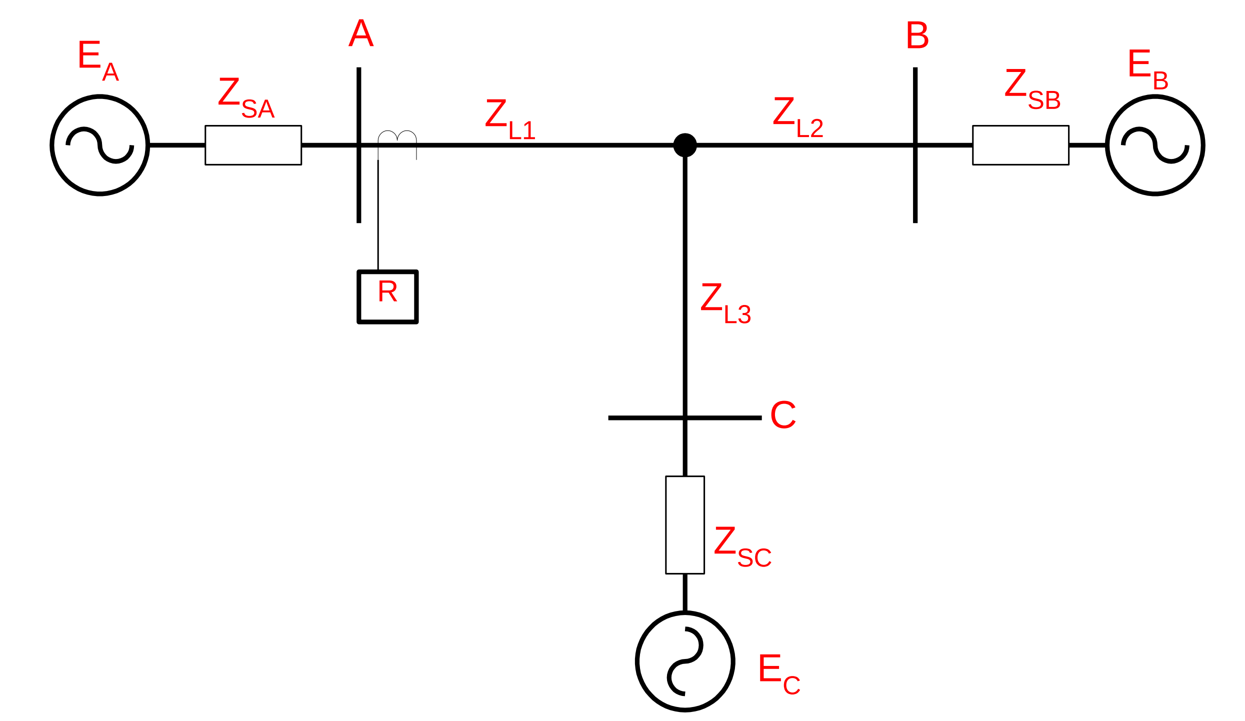


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

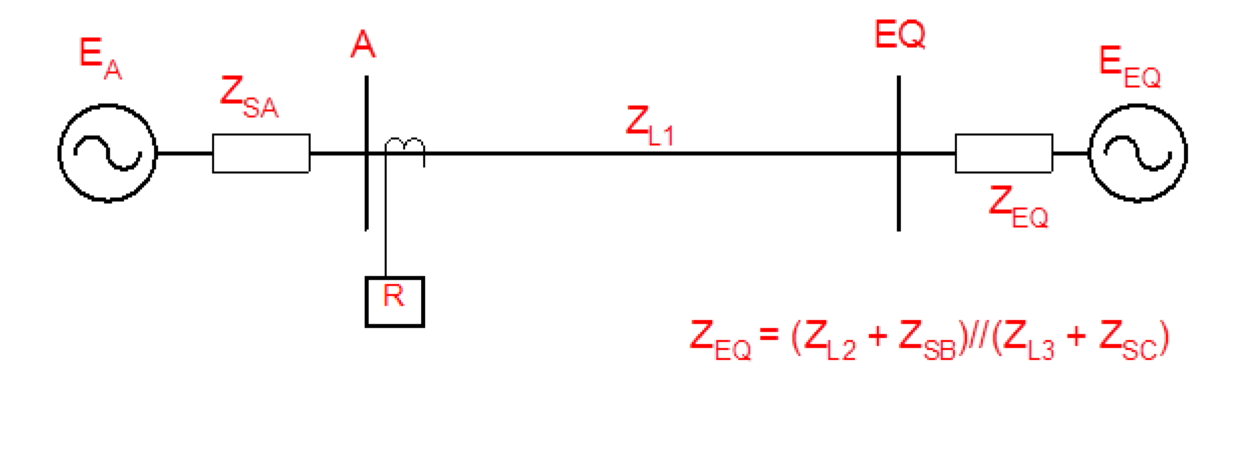


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

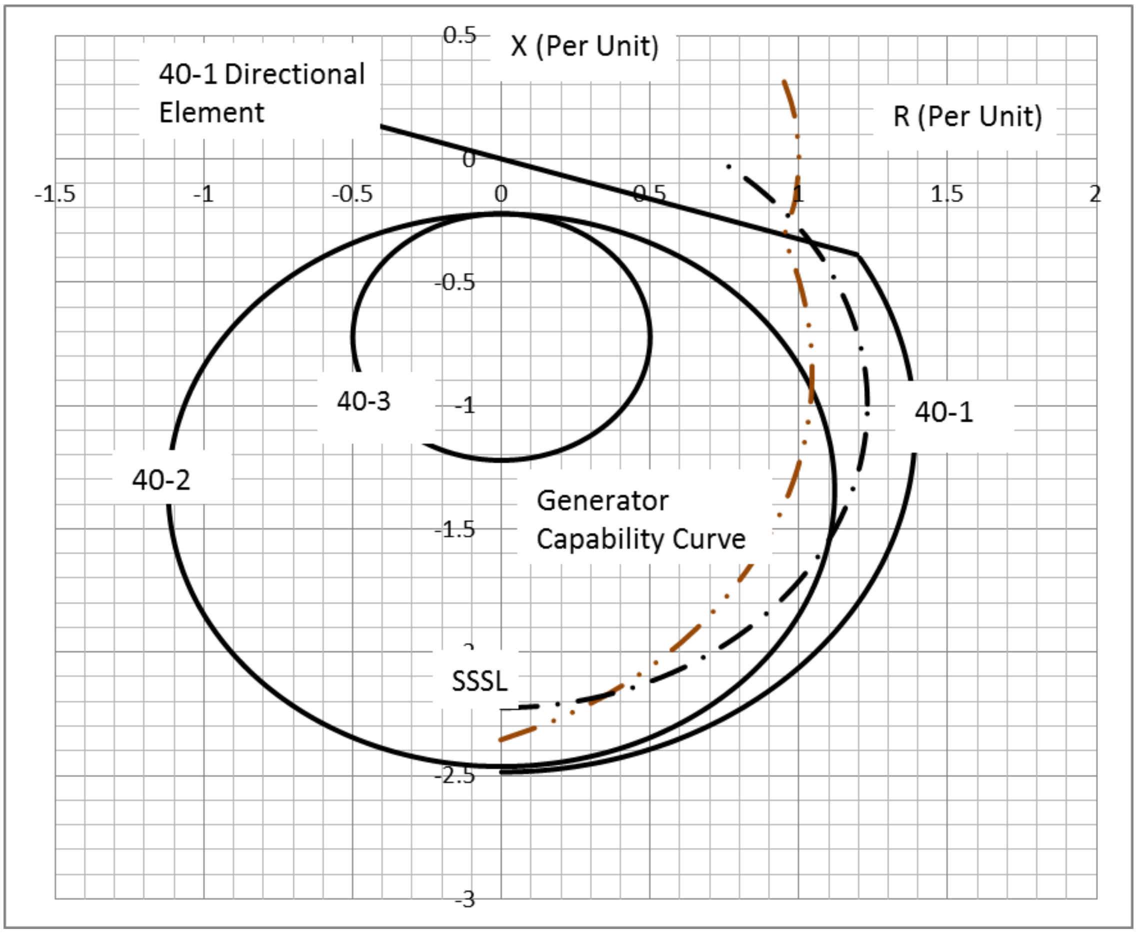


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying,* Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays,* Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

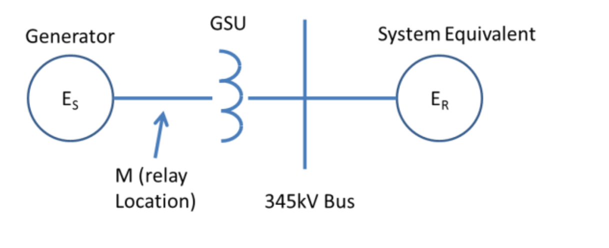

Figure 17: Simple one-line diagram of the system to be evaluated.

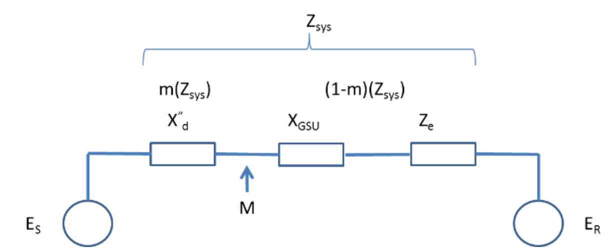

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	$\text{I (pickup)} = 5.0$ per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	$\text{Diameter} = 0.55$ per unit
	$\text{MTA} = 85°$

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

Angle (δ) (Degrees)	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

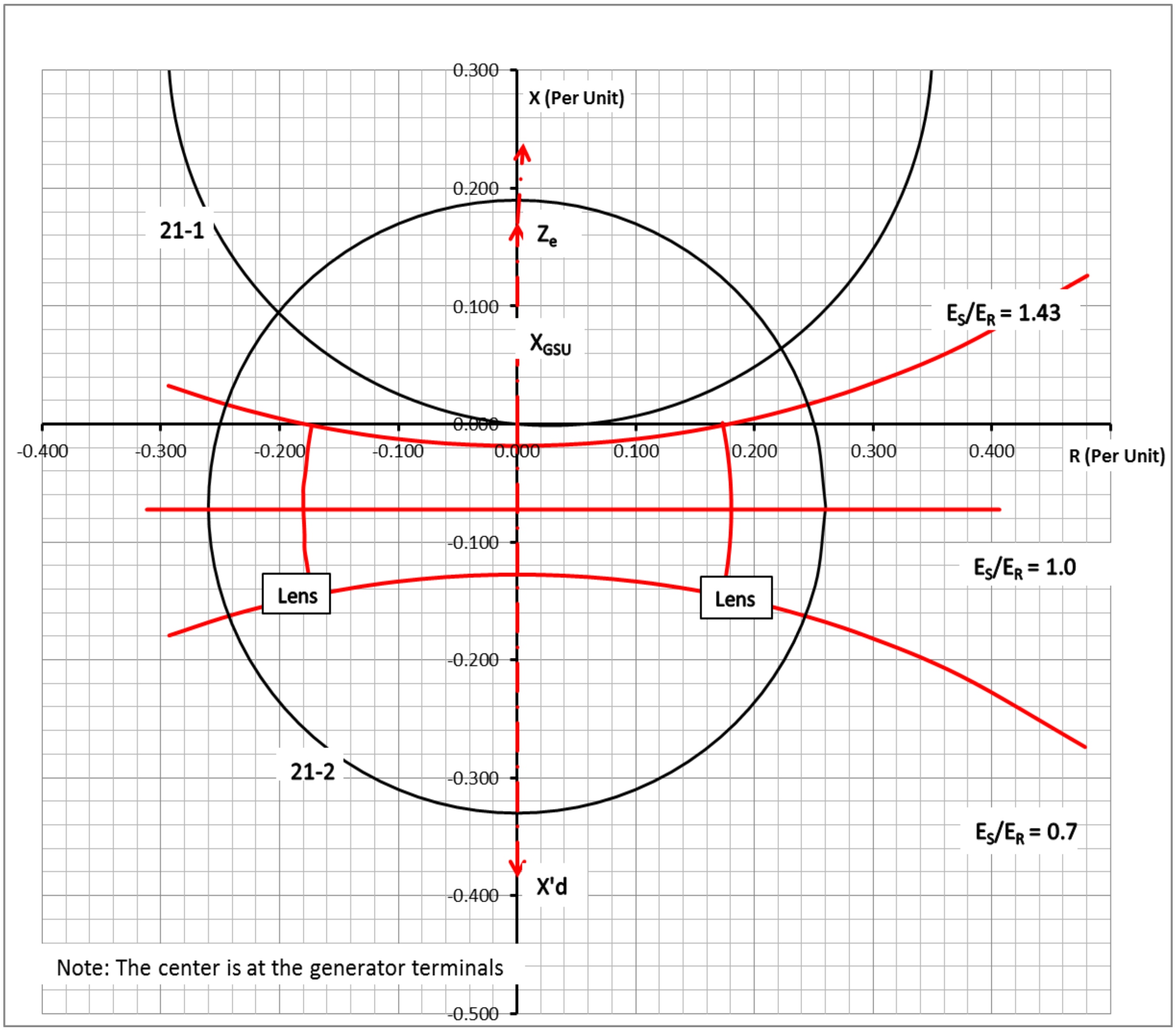

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

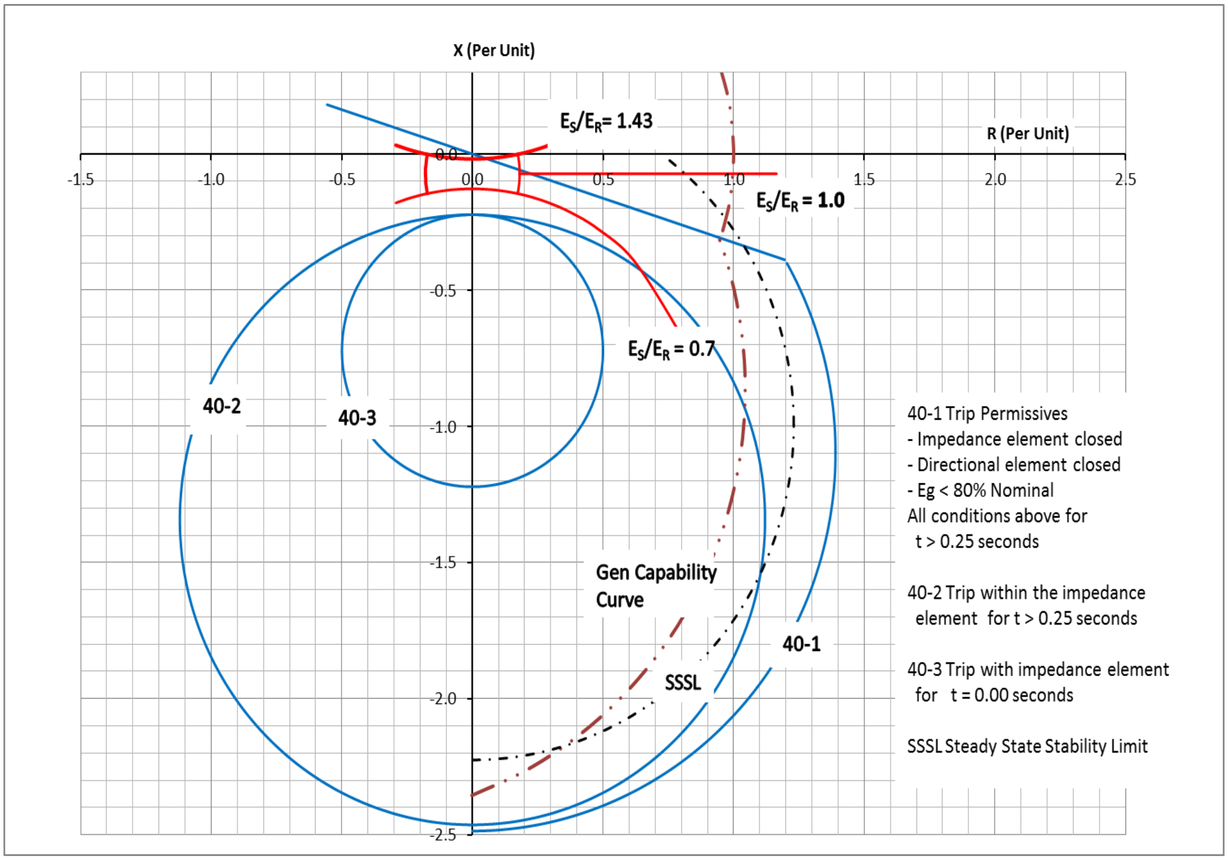

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°}pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d’), GSU transformer ($X_{T)}$, and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

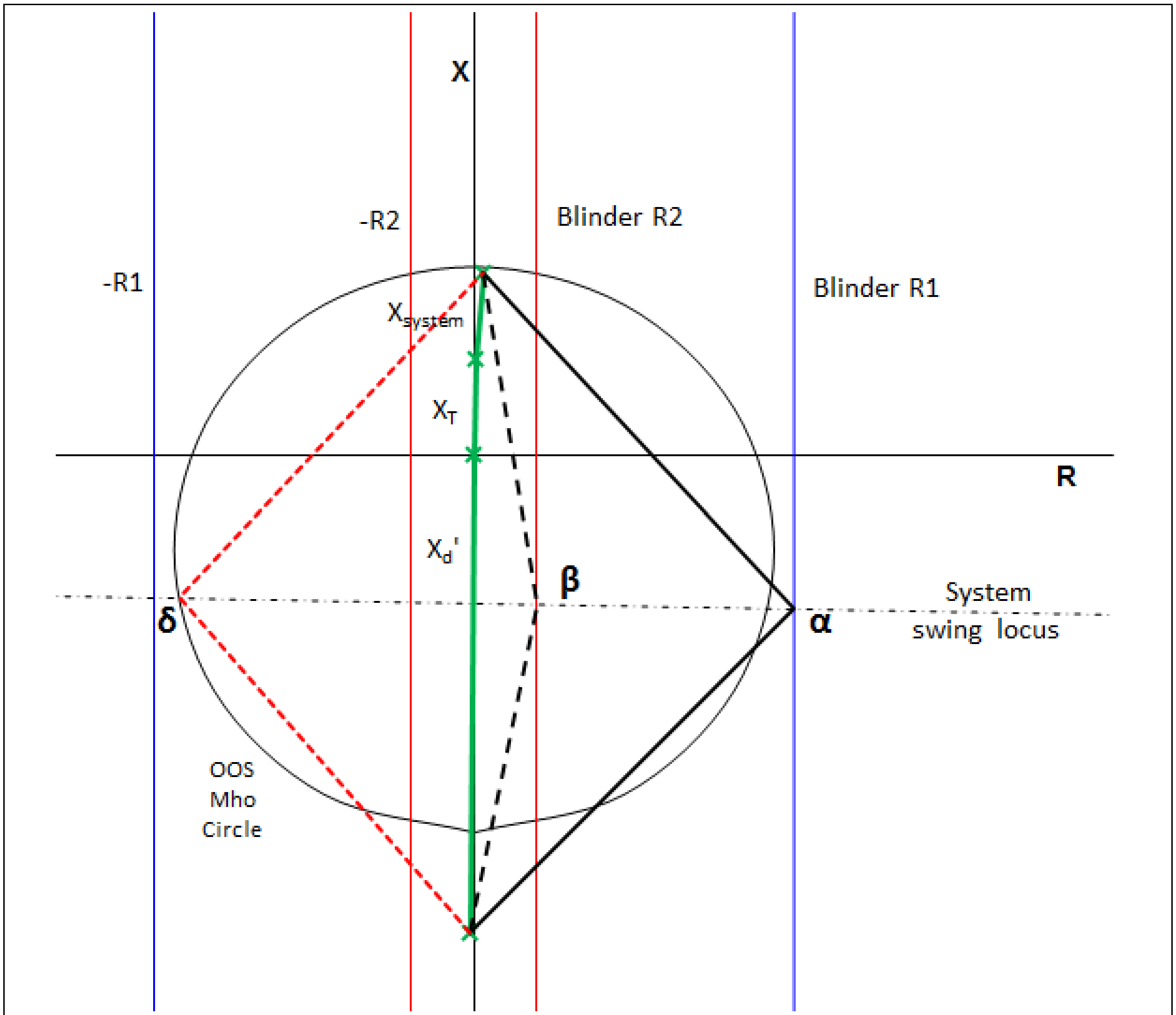

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

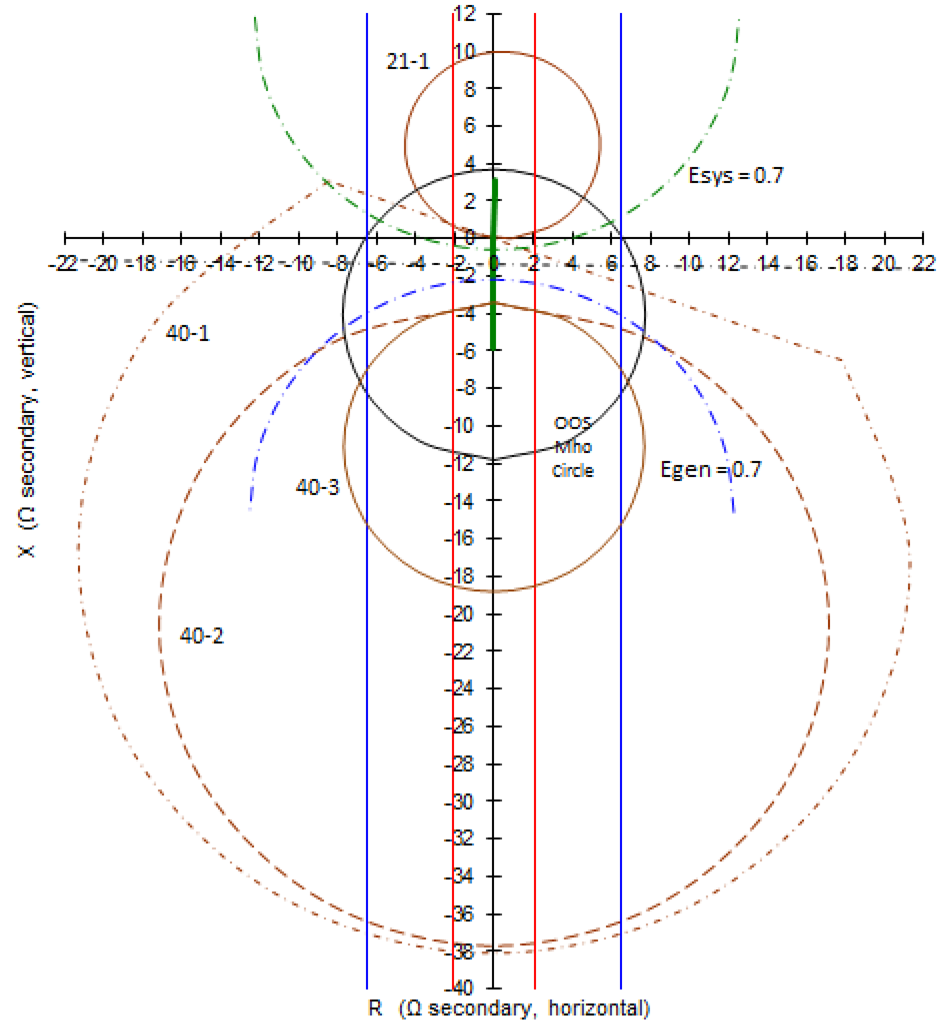

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-2 – Attachment B criteria or can be excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-2 – Attachment B criteria.

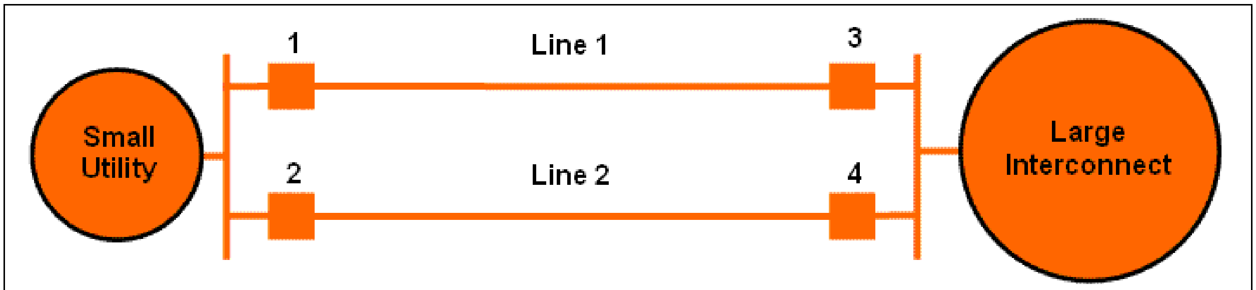

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

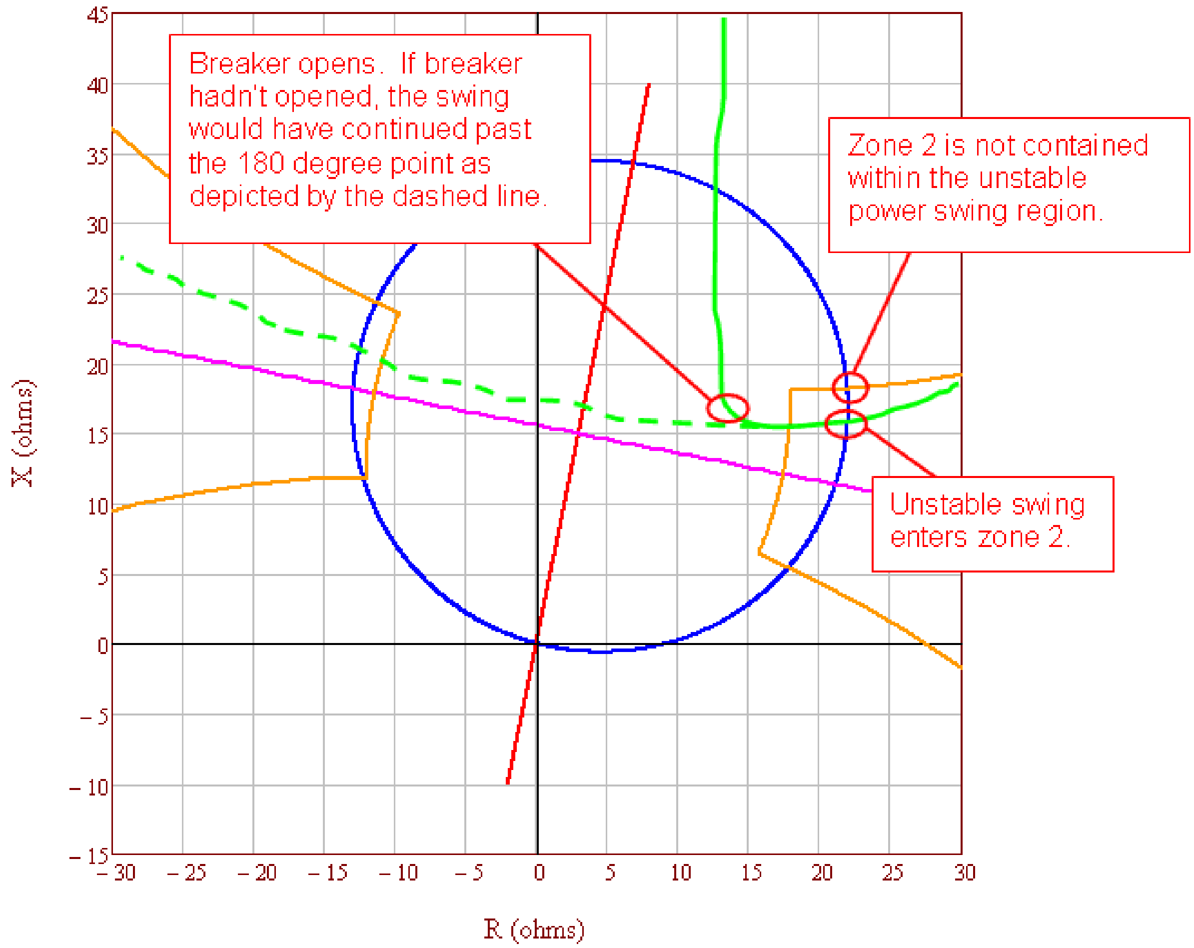

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

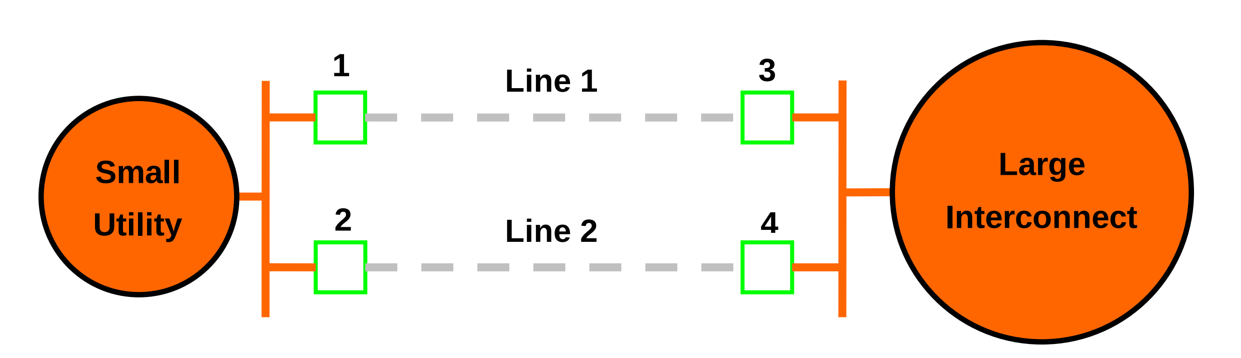

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

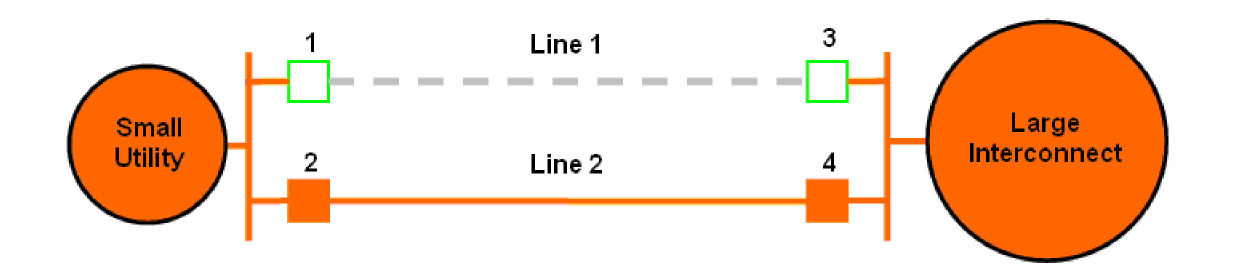

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

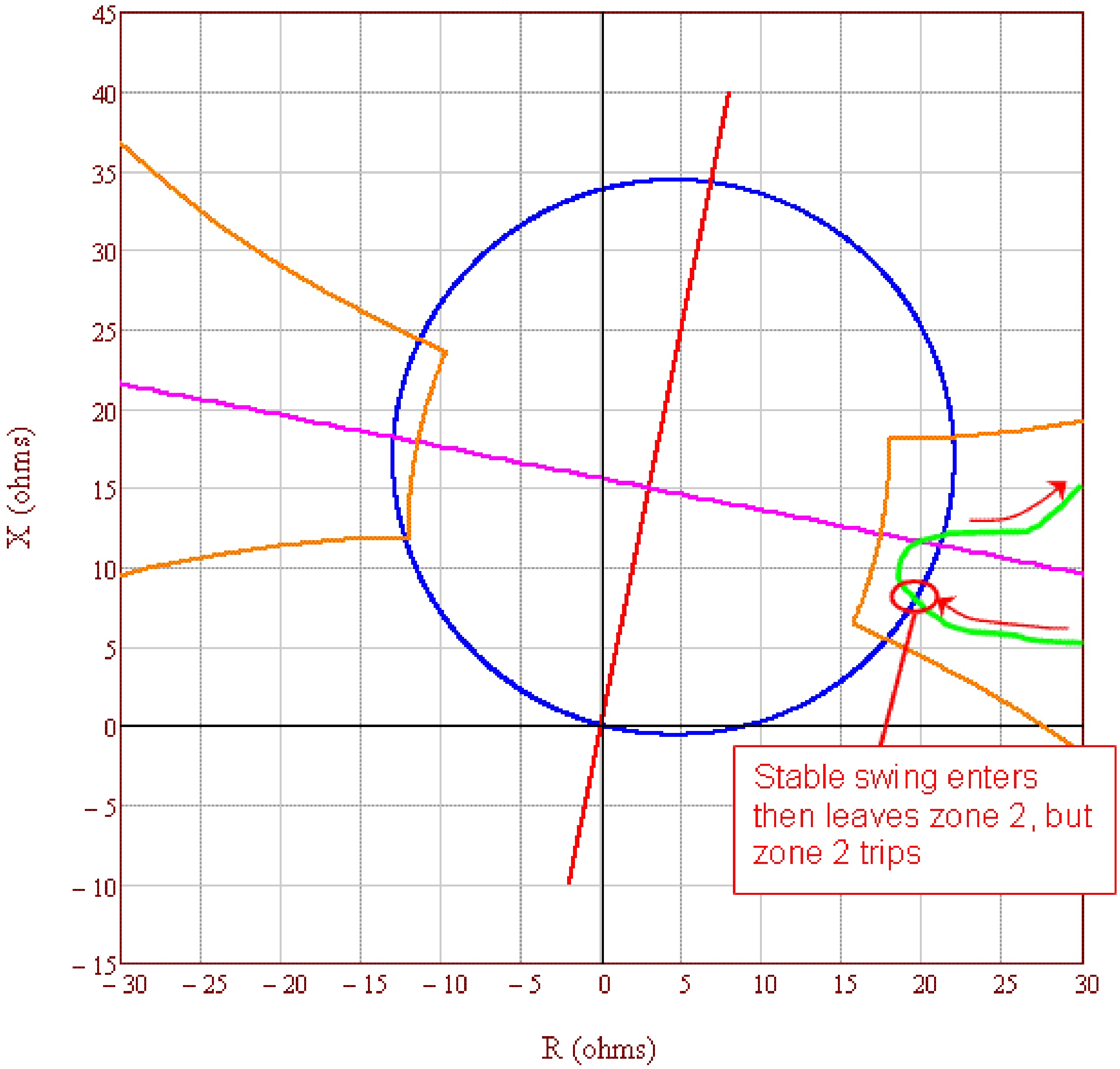

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

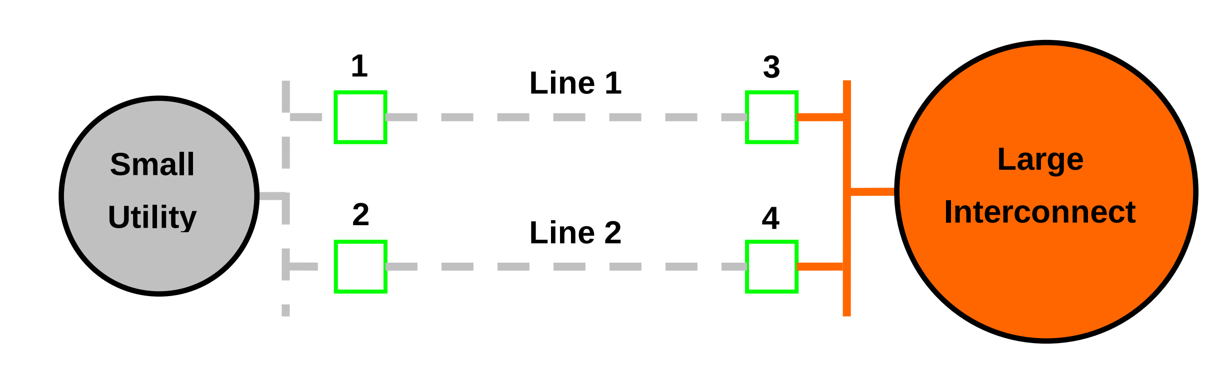

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

4.1.2 Planning Coordinator.

4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

4.2.1 Generators.

4.2.2 Transformers.

4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. **Effective Dates:** **See Implementation Plan**

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Planning Horizon for a planning event,~~–~~ , ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Planning Horizon for a planning event~~.~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-~~1~~2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-~~1~~2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-~~1~~2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, “Becoming Aware of an Element That Tripped in Response to a Power Swing.”

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, “Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis.”

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	TBD	Adopted by NERC Board of Trustees	

PRC-026-~~1~~ 2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., “load-responsive”) including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-~~1~~ 2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-~~1~~2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-~~1~~2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-2~~1~~ Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-~~1~~2 – Attachment B.

[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., “TPL”) and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the~~ any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission ~~lines to~~lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-~~1~~ 2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-~~1~~2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-~~1~~2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-~~1~~2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1)
$$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-~~1~~ 2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-~~1~~ 2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-~~1~~ 2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-~~1~~ 2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-~~1~~ 2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-~~1~~ 2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-~~1~~2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-~~1~~2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-~~1~~2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

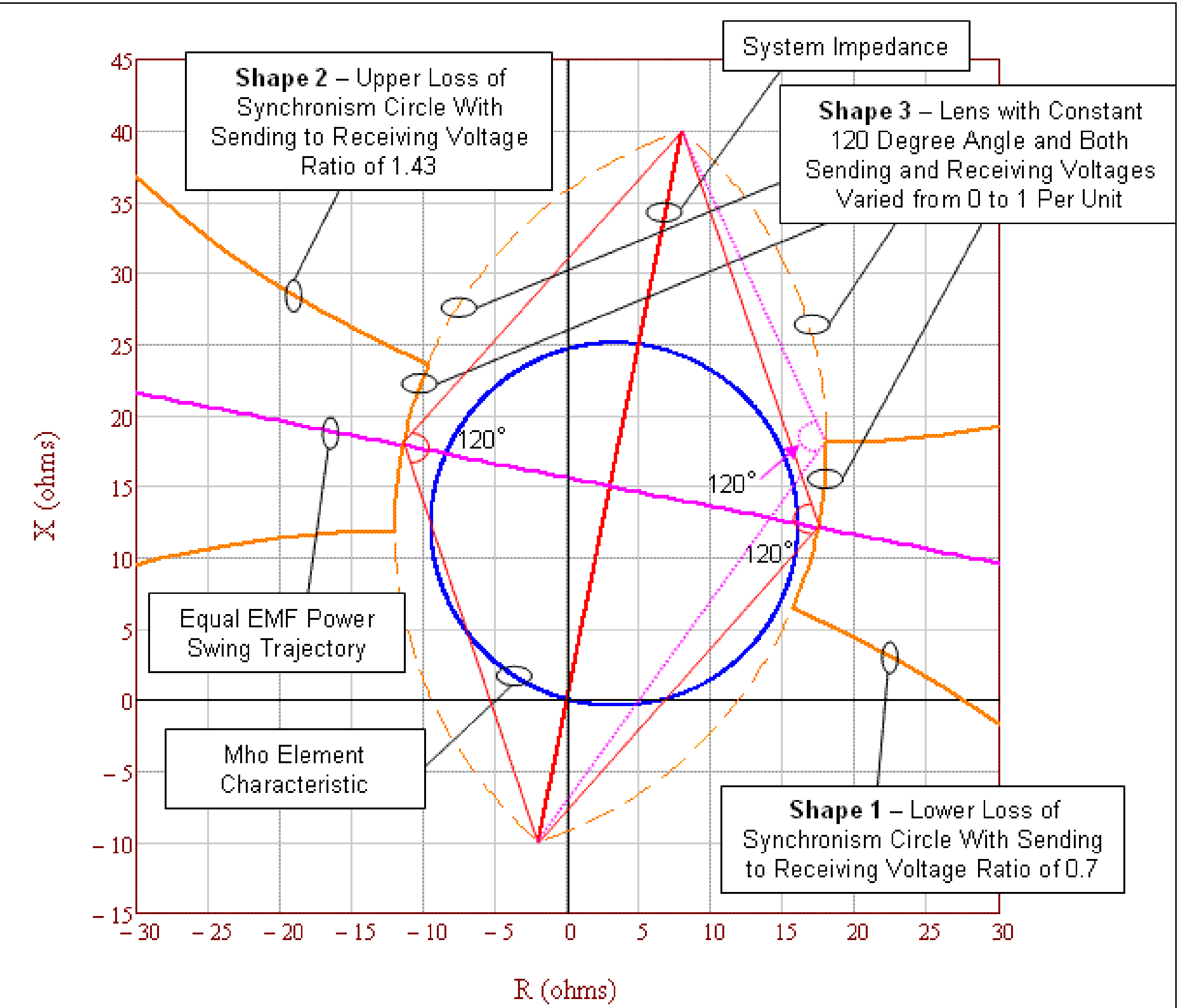

Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1.

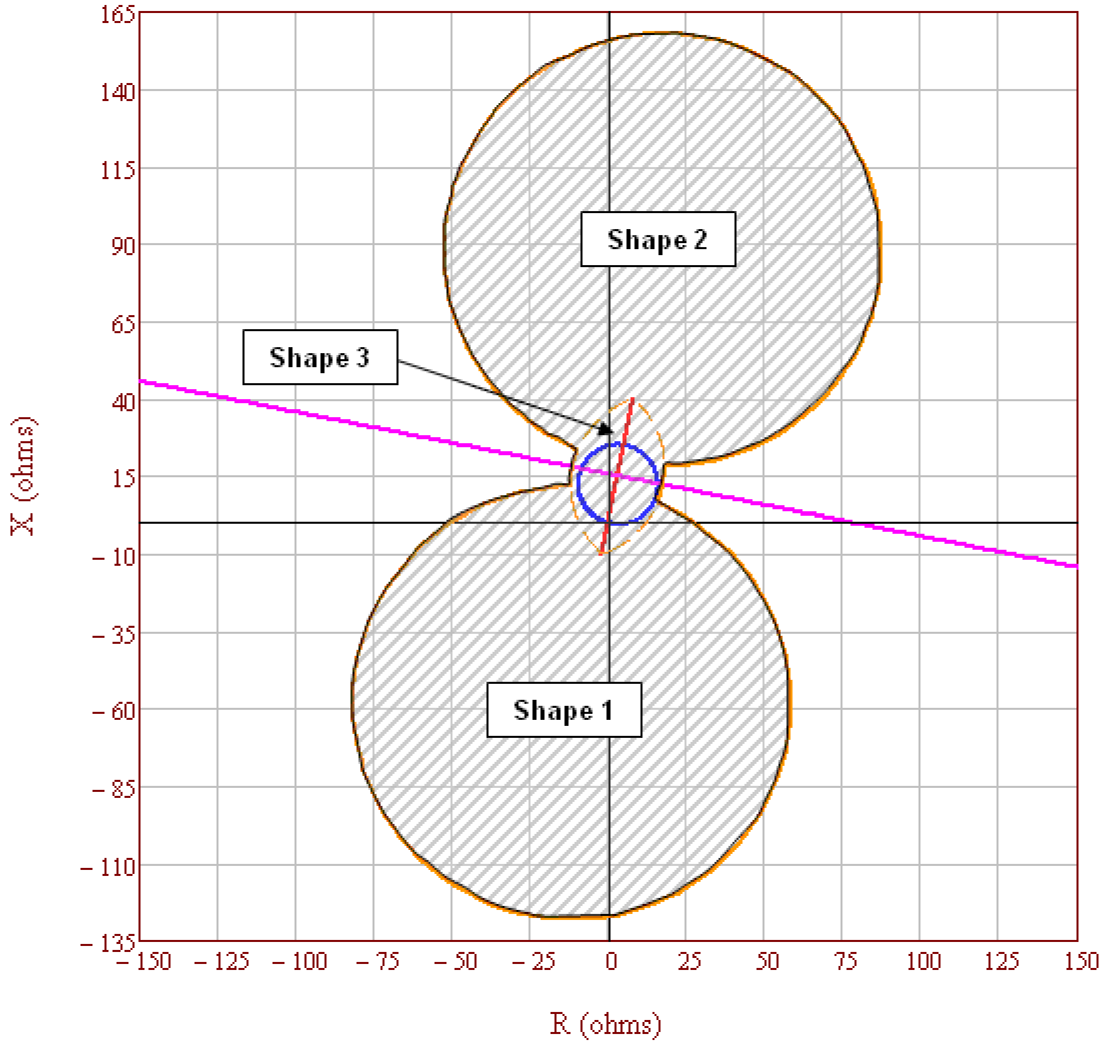

Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No.1.

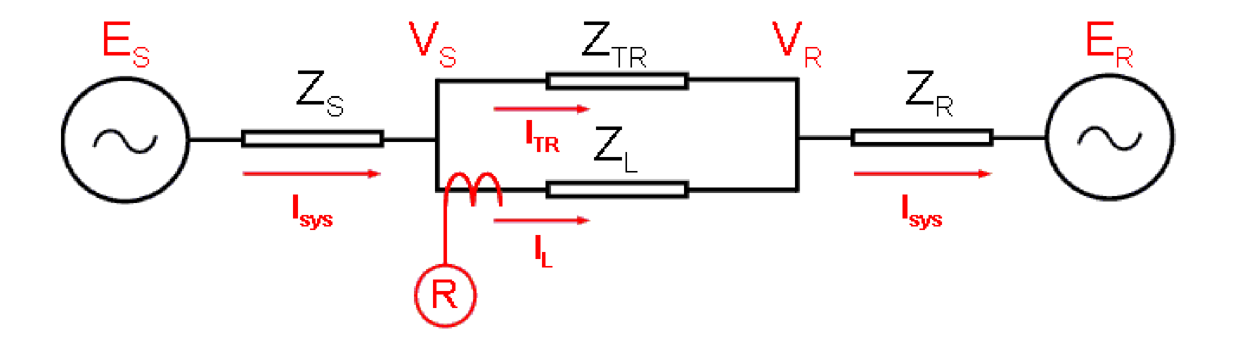

Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

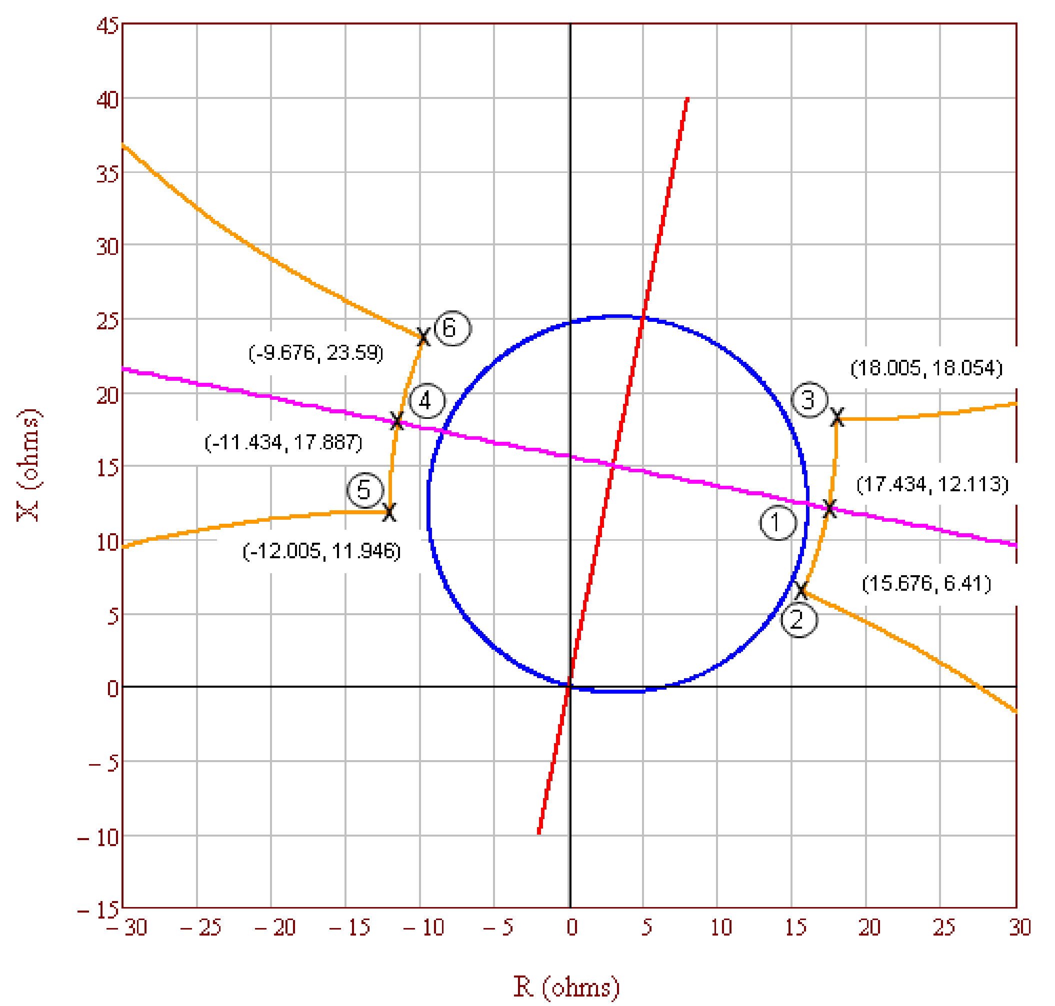

Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4+j20)\times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4+j20)\,\Omega \times (4+j20) \times 10^{10}\,\Omega\right)}{\left((4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega\right)}$
	$Z_{total} = 4 + j20\,\Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\,\Omega + (4+j20)\,\Omega + (4+j20)\,\Omega$
	$Z_{sys} = 10 + j50\,\Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\,V - 132{,}791\angle 0°\,V}{(10+j50)\,\Omega}$
	$I_{sys} = 3{,}854\angle 77°\,A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\,A \times \frac{(4+j20) \times 10^{10}\,\Omega}{(4+j20)\,\Omega + (4+j20) \times 10^{10}\,\Omega}$
	$I_L = 3{,}854\angle 77°\,A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\,V - [(2+j10\,)\Omega \times 3{,}854\angle 77°\,A]$
	$V_S = 65{,}271\angle 99°\,V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120° \, V - 92{,}953.7\angle 0° \, V}{(10 + j50)\, \Omega}$
	$I_{sys} = 3{,}854\angle 65.5° \, A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20)\, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 65.5° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10)\, \Omega \times 3{,}854\angle 65.5° \, A]$
	$V_S = 98{,}265\angle 110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6° \, V}{3{,}854\angle 65.5° \, A}$
	$Z_{L-Relay} = 18.005 + j18.054 \, \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1°\, A]$
	$V_S = 95{,}756\angle - 106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}756\angle - 106.1°\, V}{4{,}511\angle 131.1°\, A}$
	$Z_{L-Relay} = -11.434 + j17.887\,\Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\,\Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle - 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$

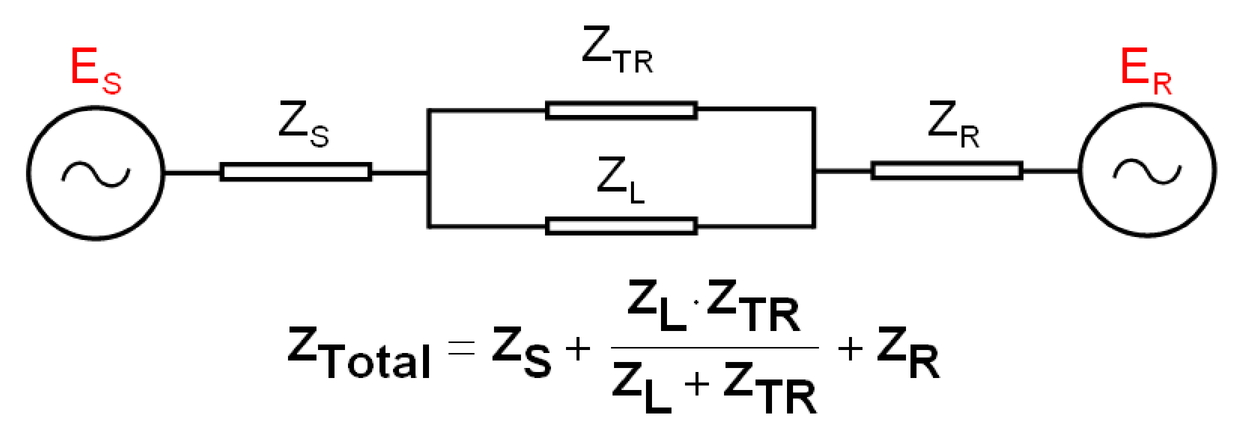

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

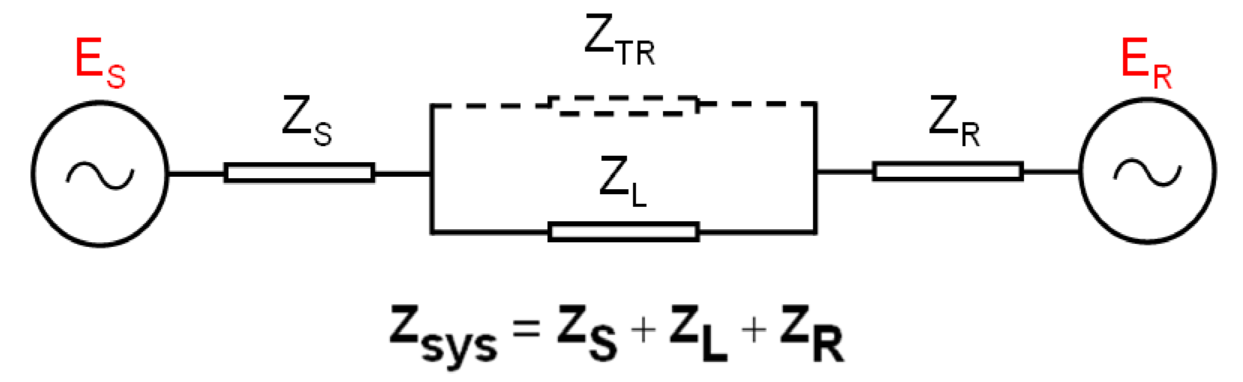

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

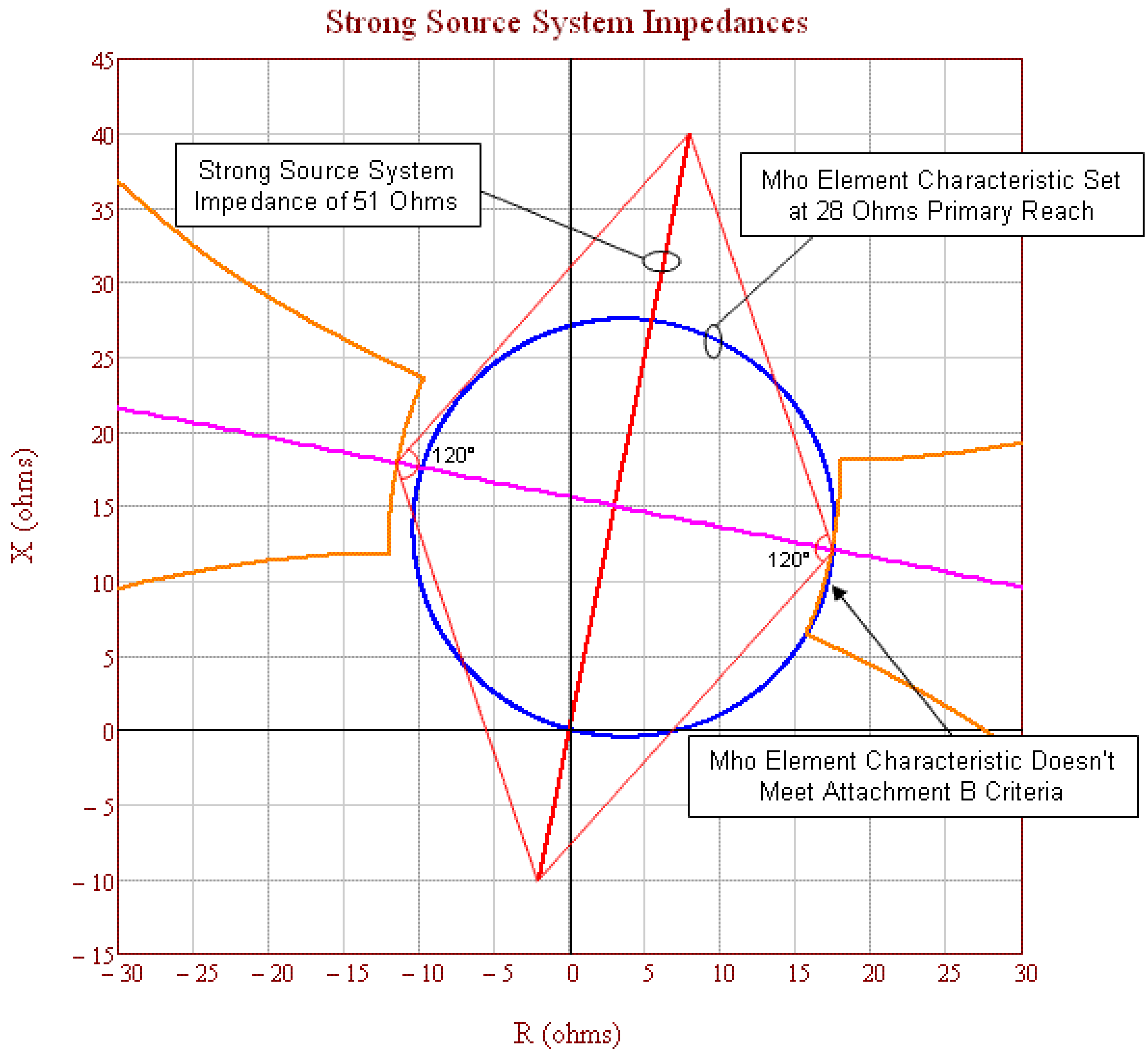

Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-~~1~~2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

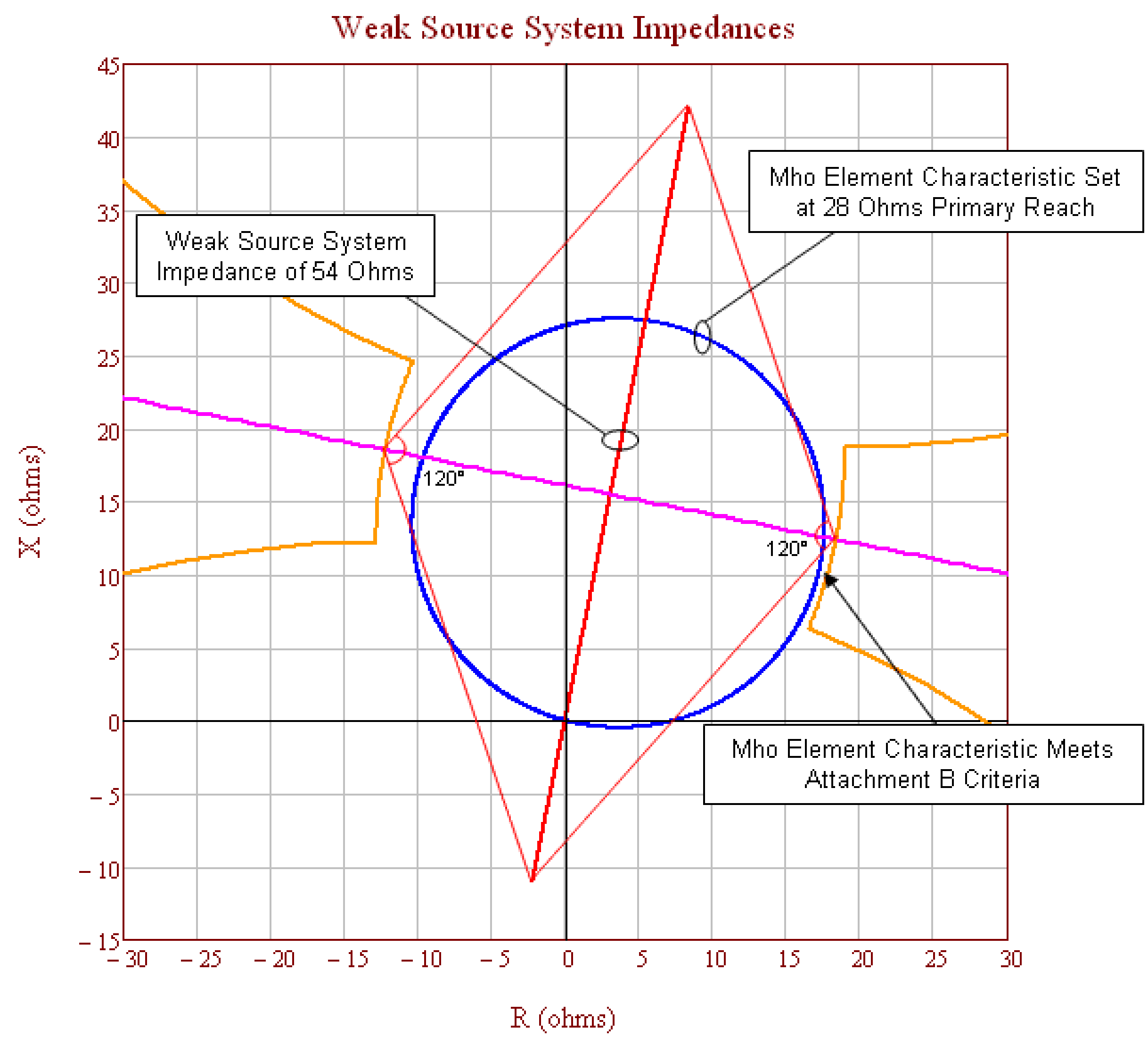

Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

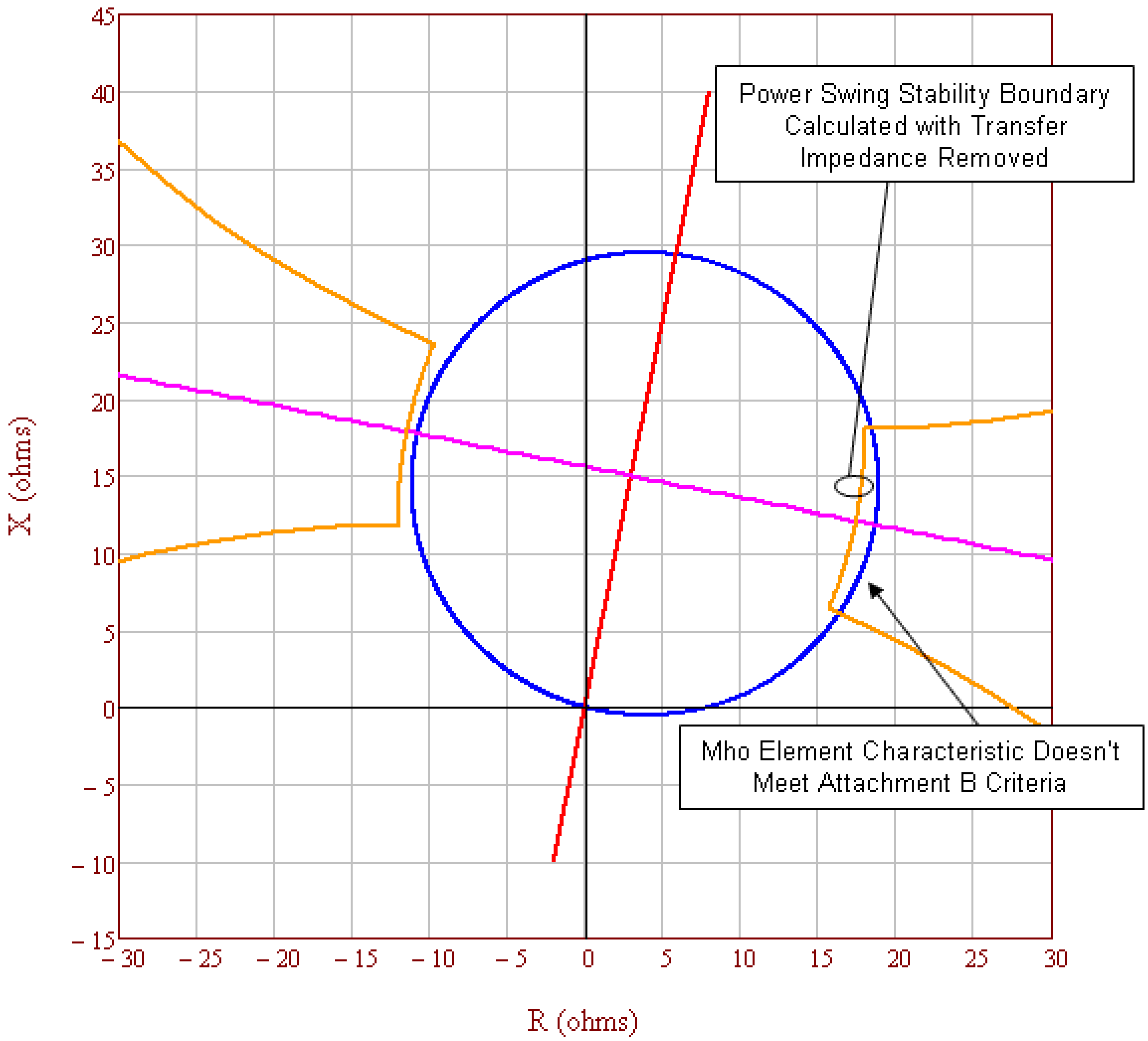

Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

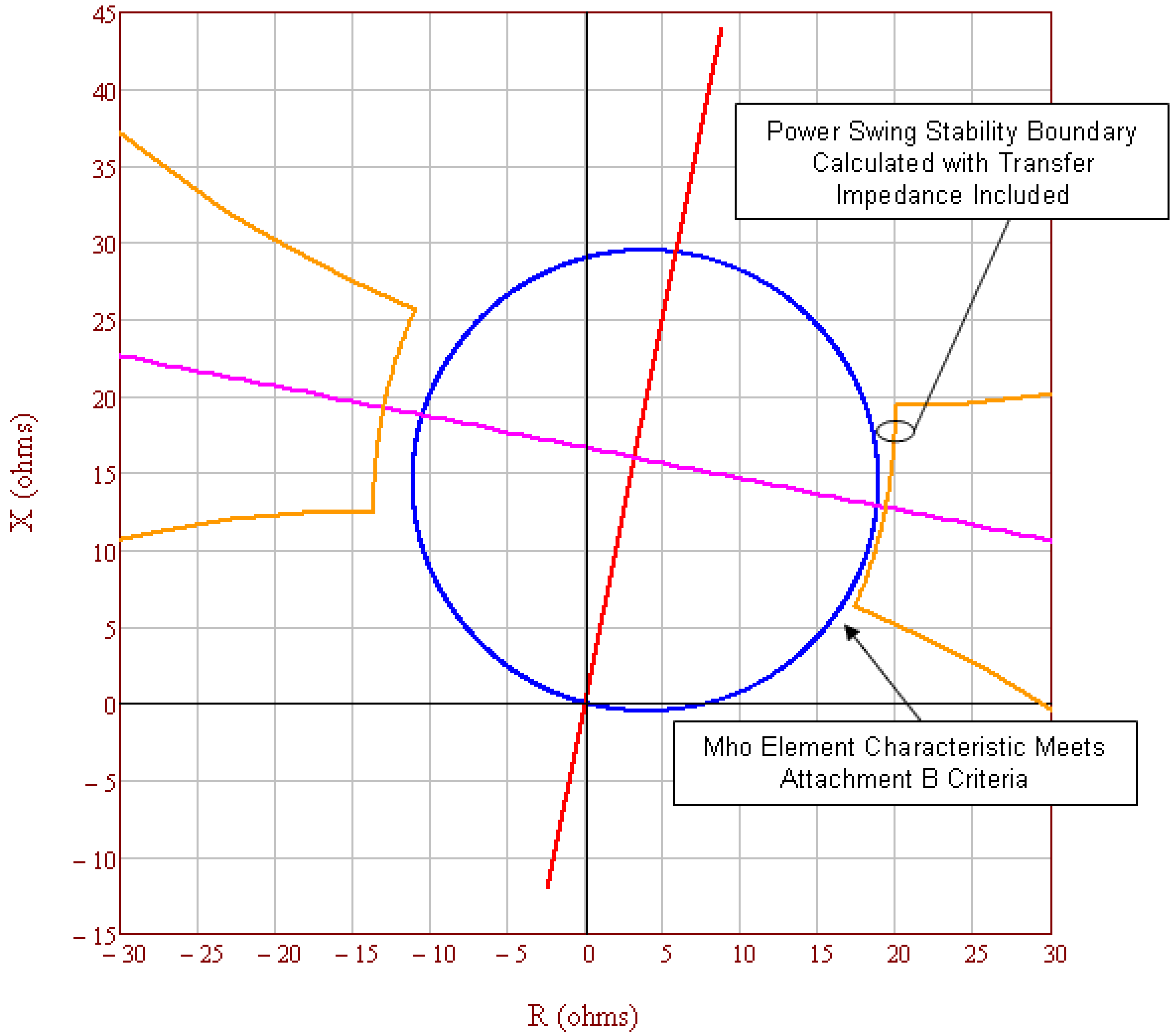

Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-~~1~~ 2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~ 2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-~~1~~ 2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~ 2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

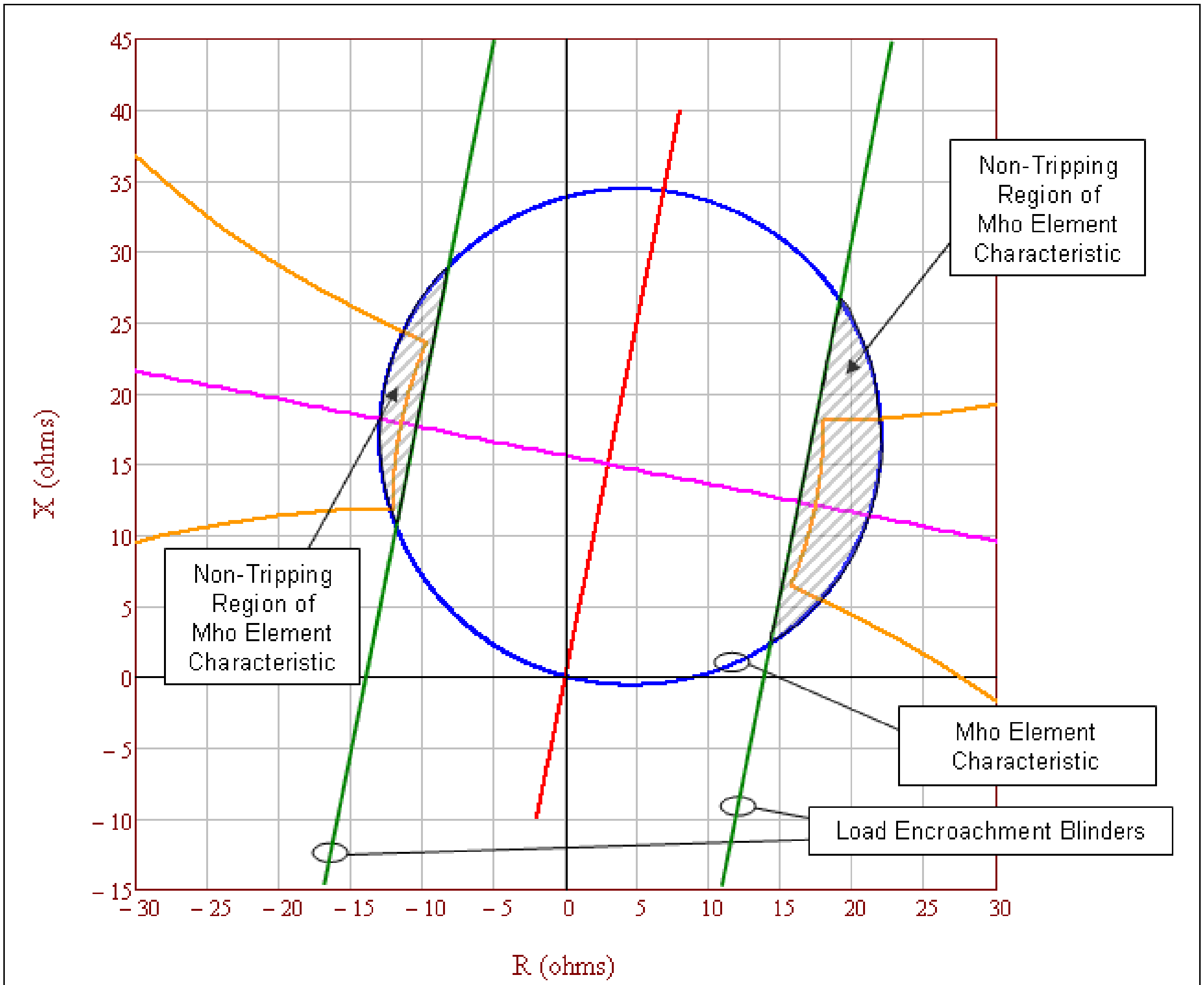

Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-~~1~~2– Attachment B, Criterion A.

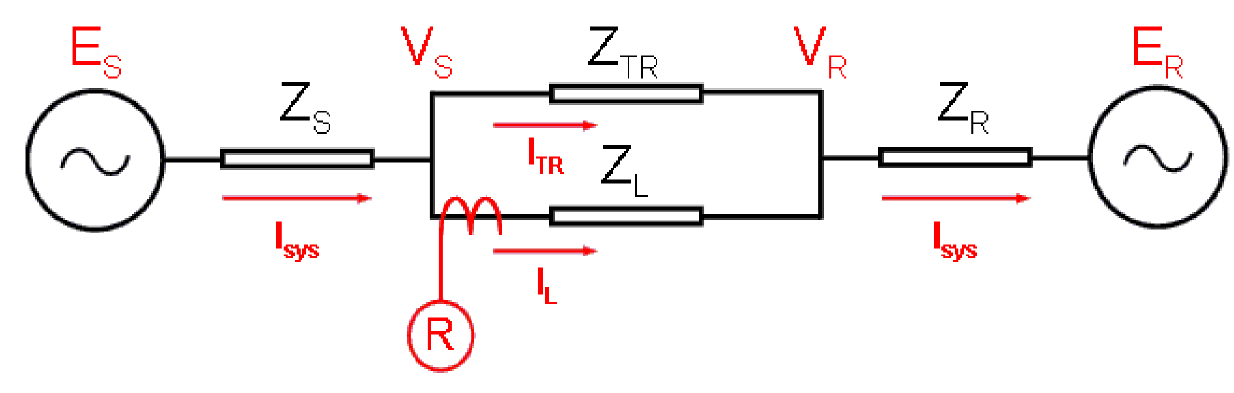

Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \dfrac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \dfrac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \dfrac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \dfrac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \dfrac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \dfrac{V_S}{I_L} = Z_L + Z_R + \dfrac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

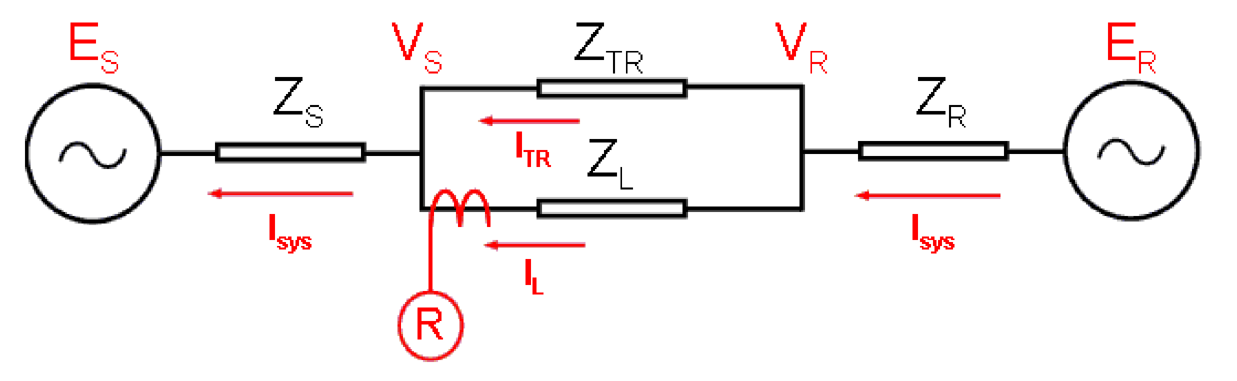

Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

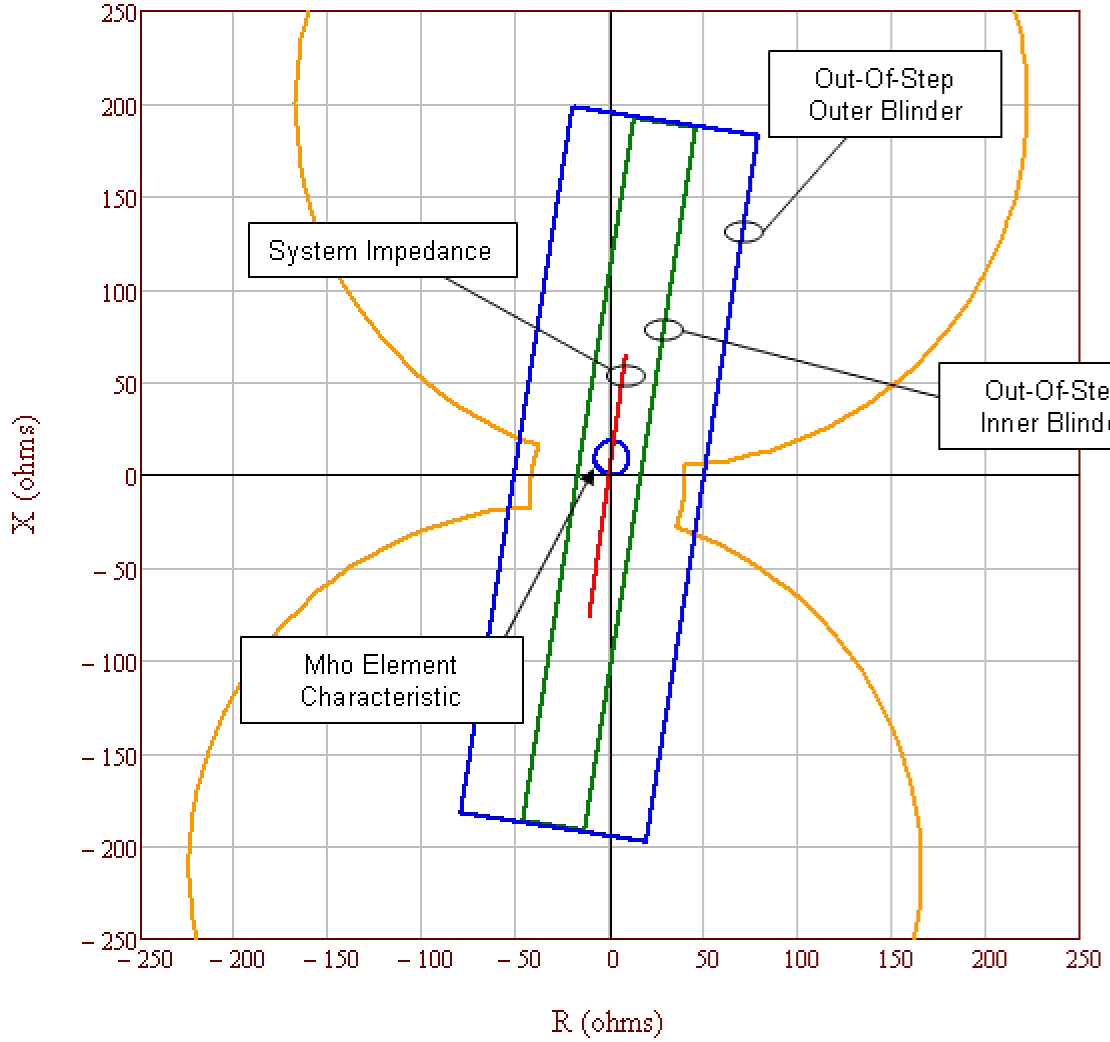

Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

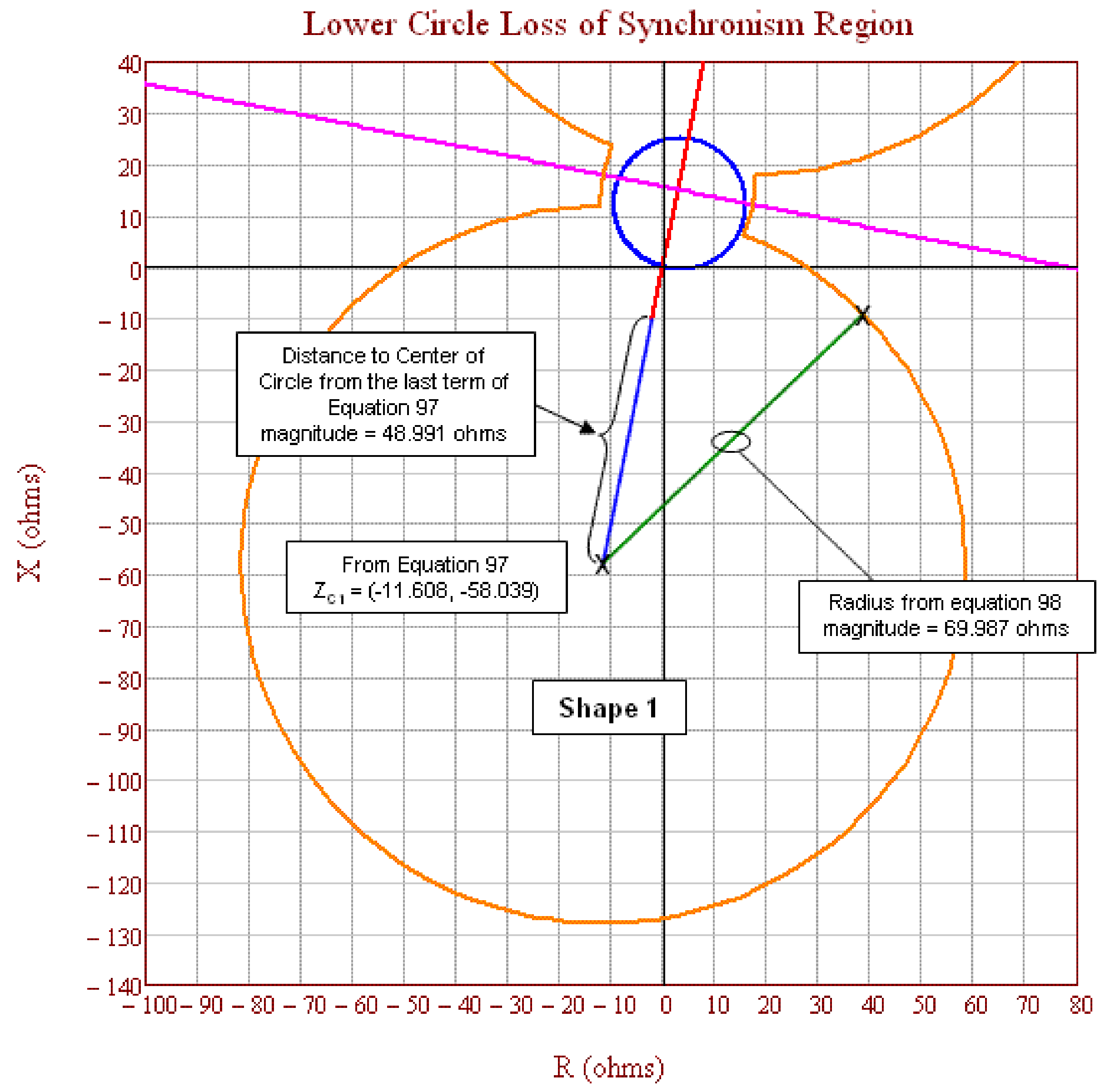

Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

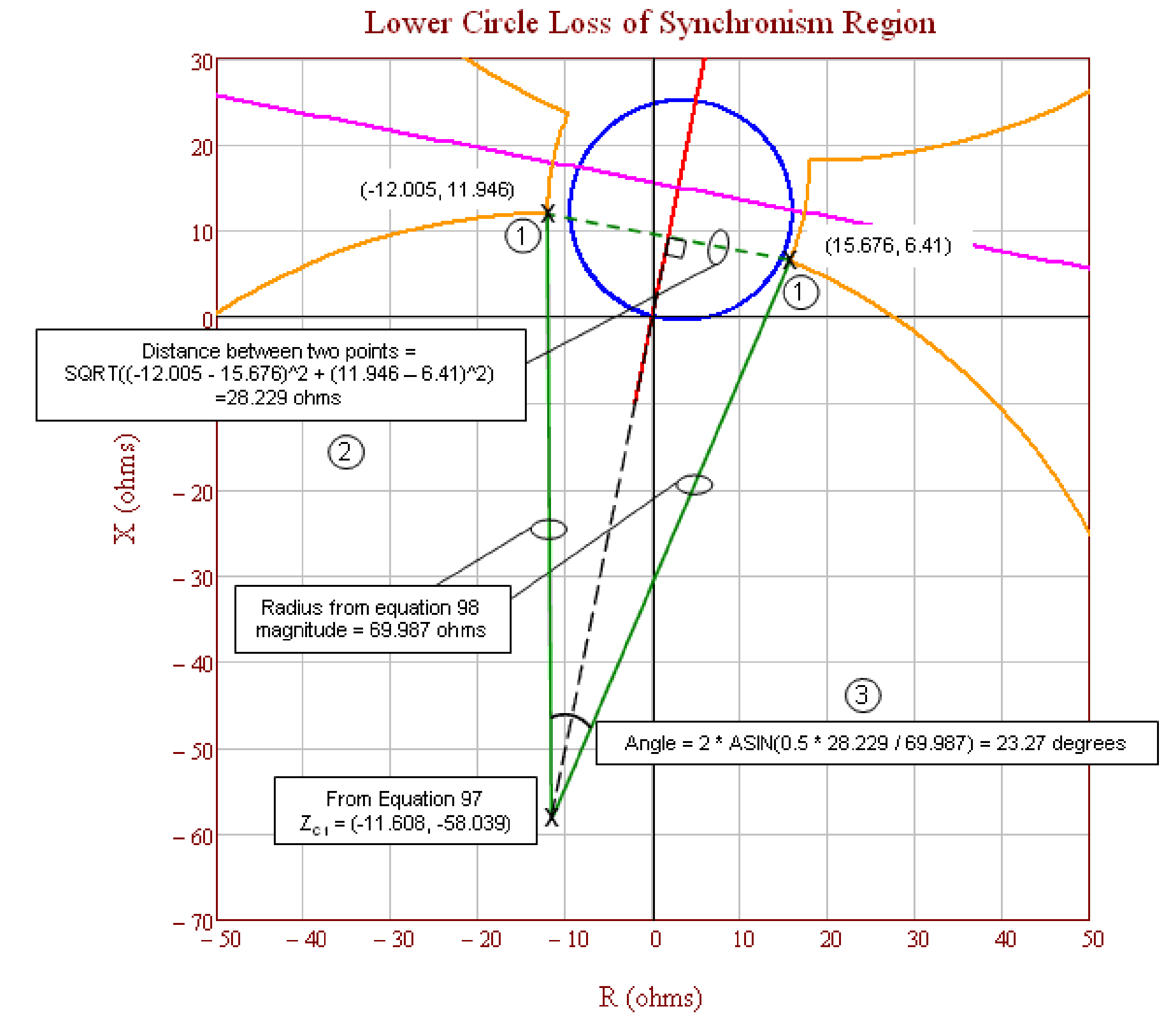

Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

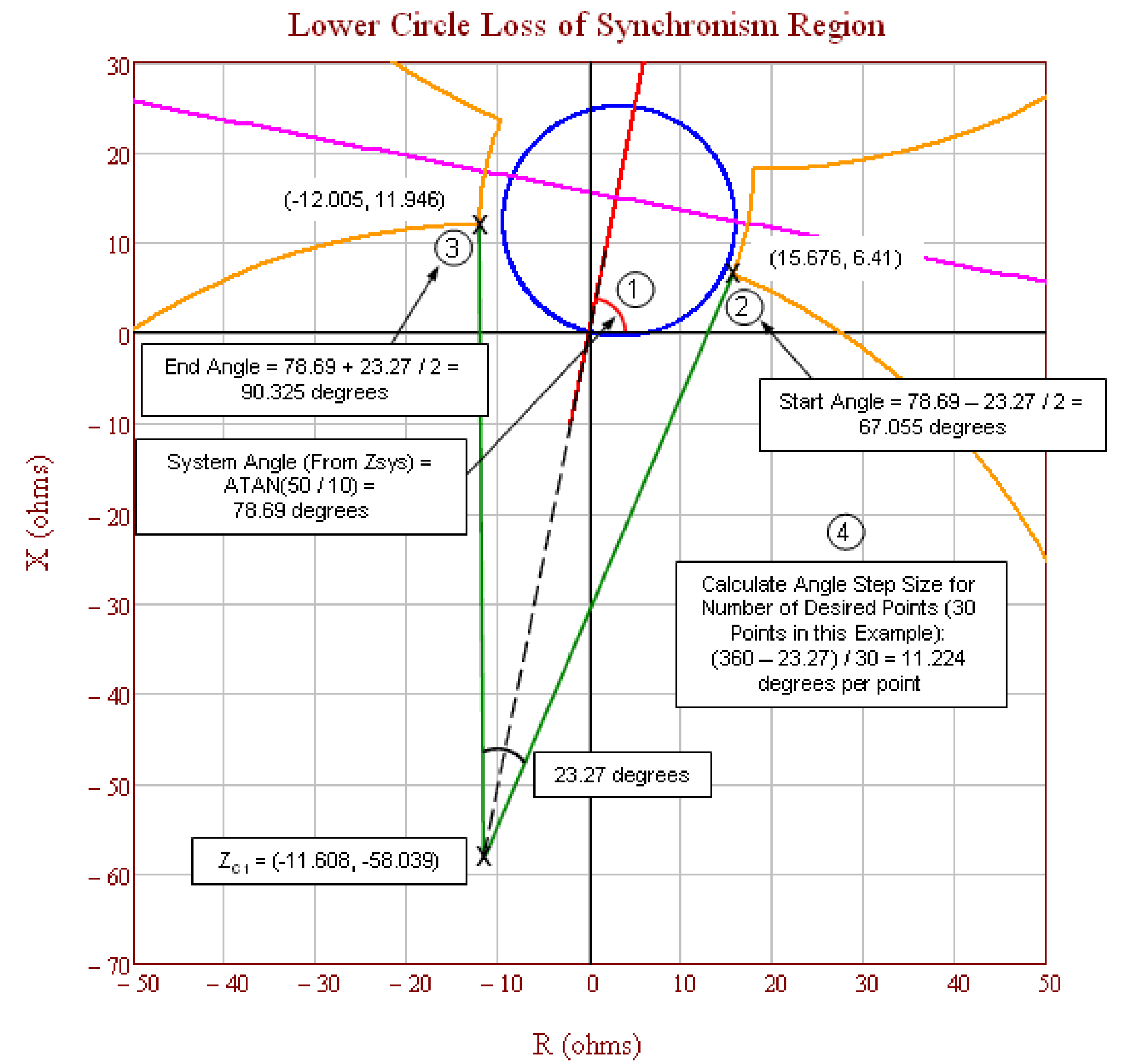

Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

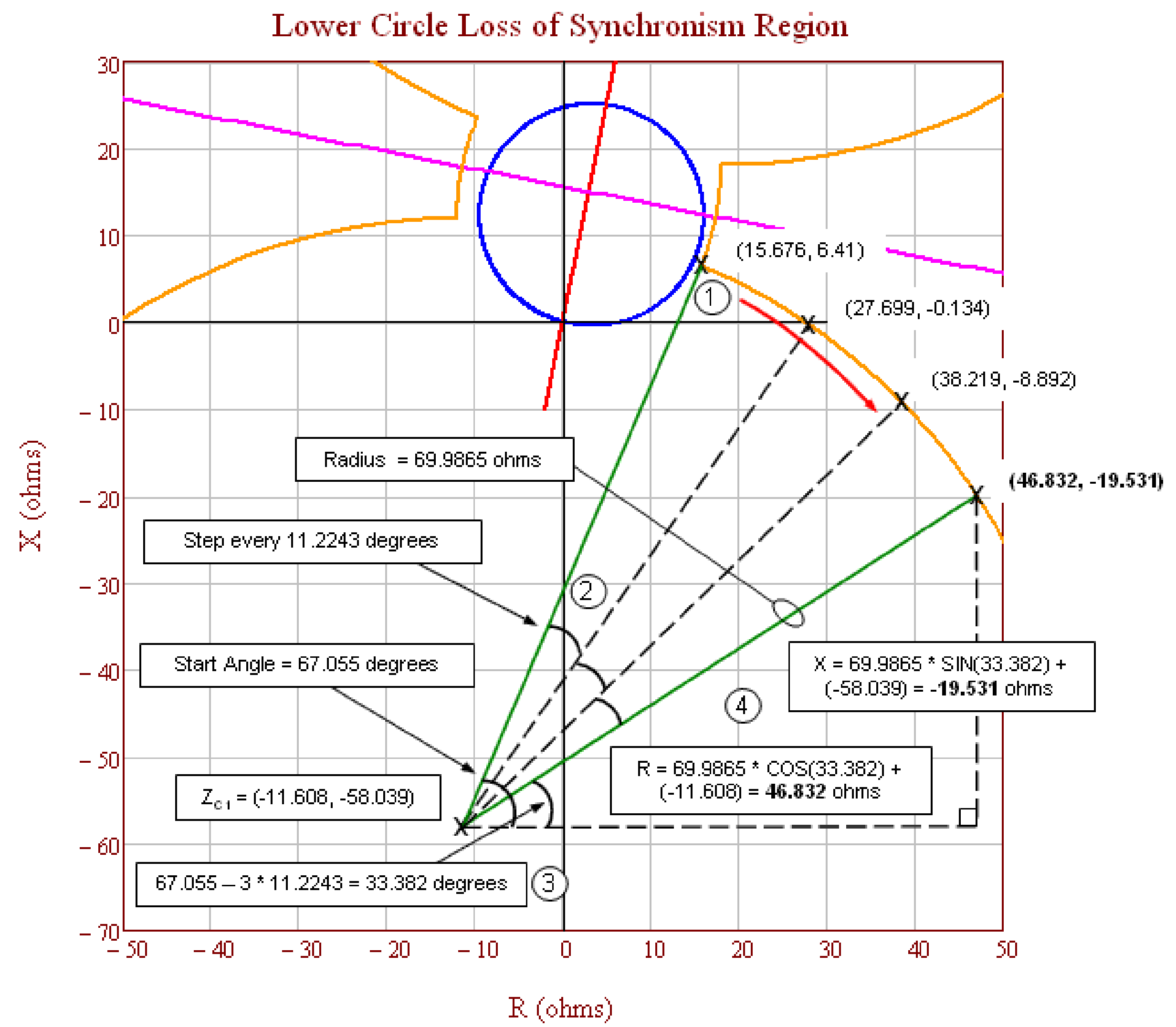

Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

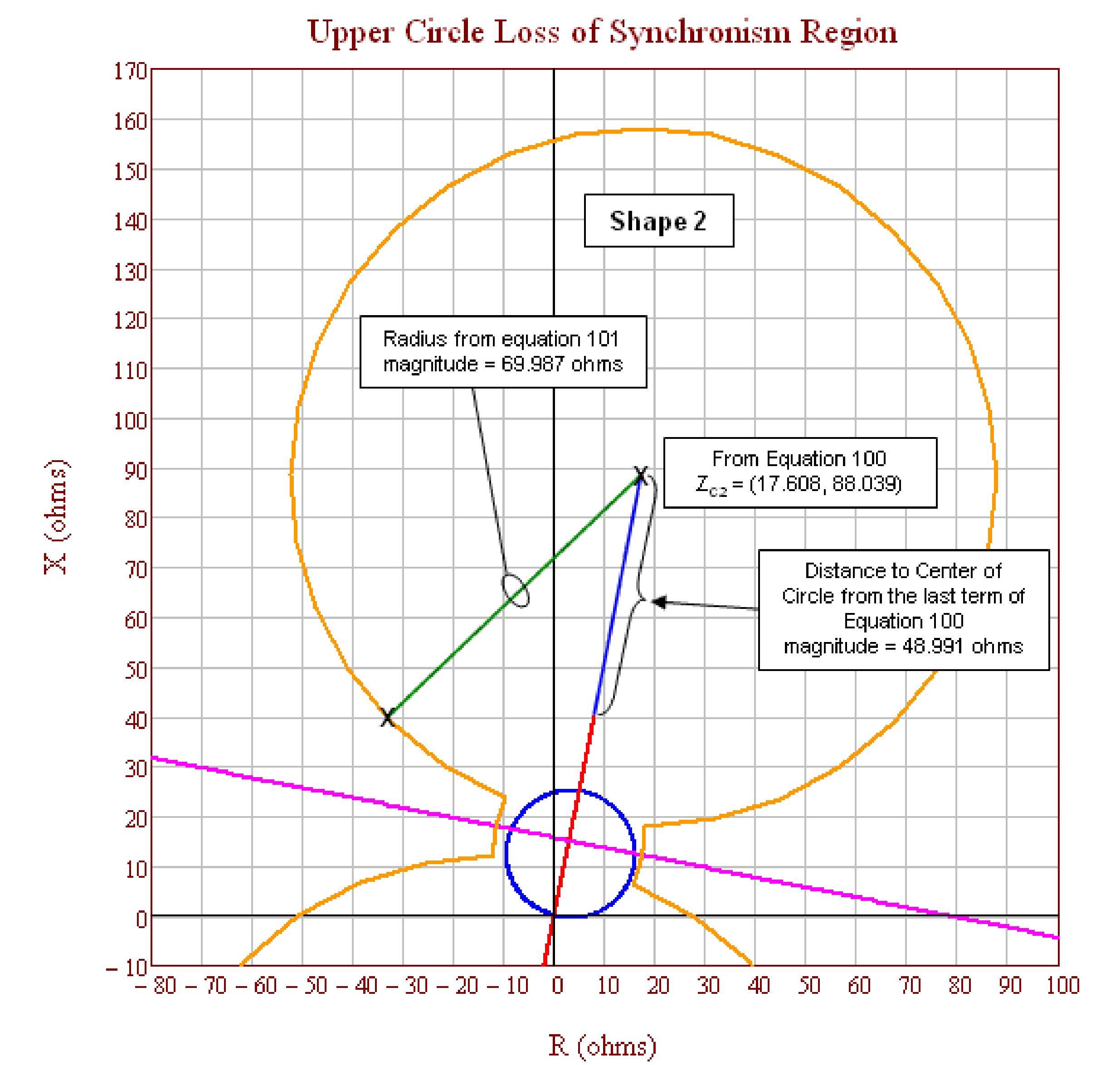

Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

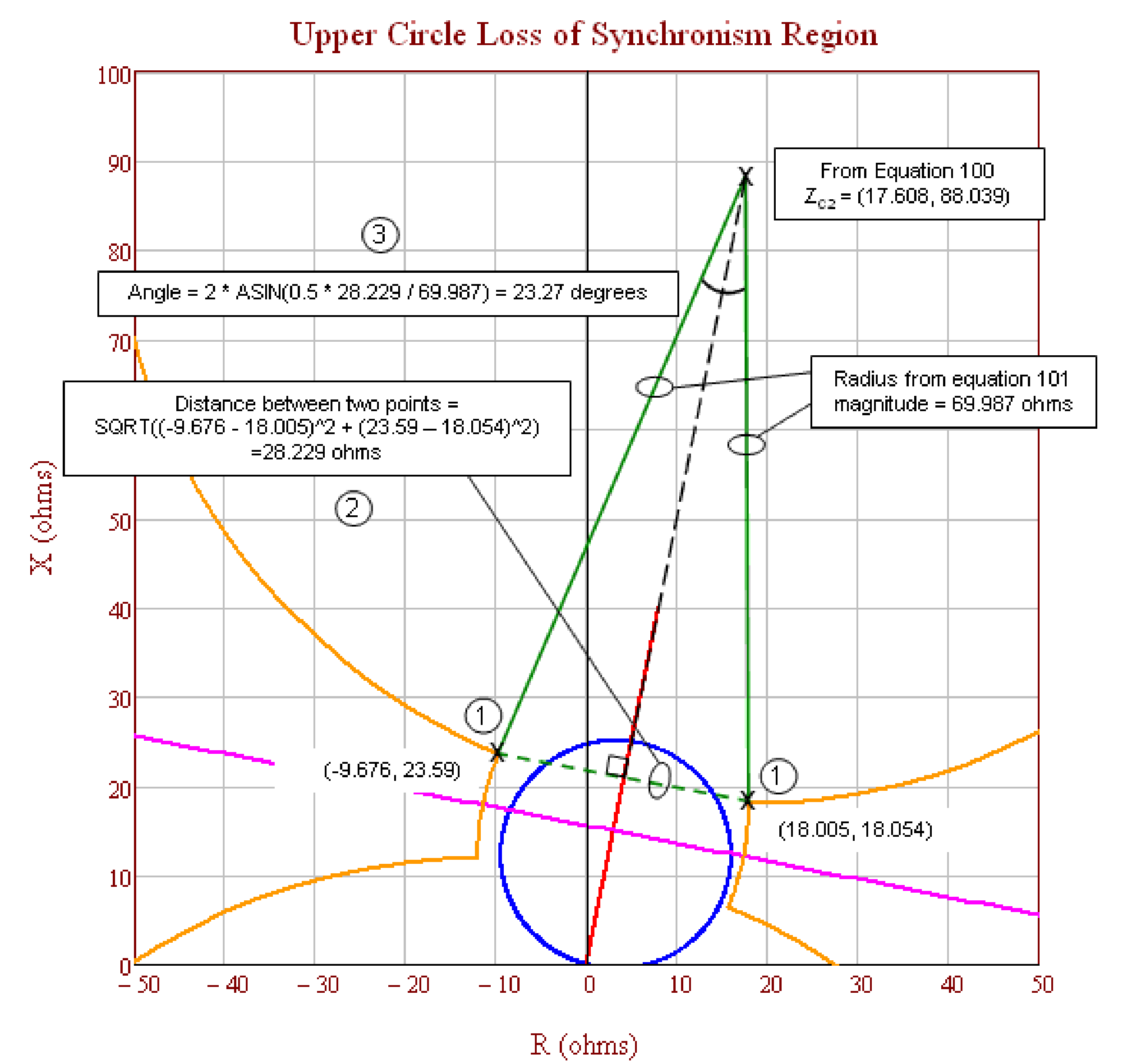

Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

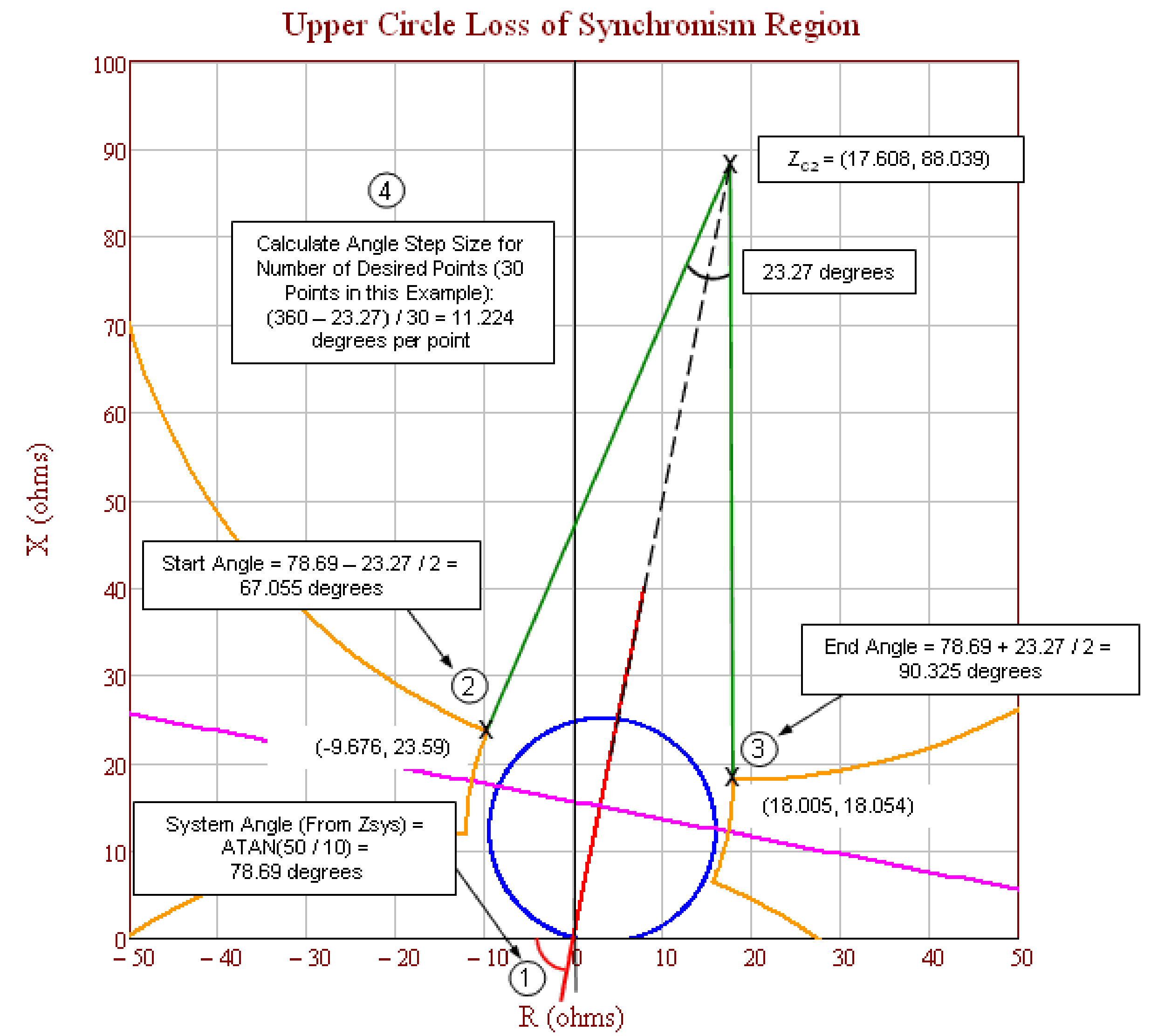

Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

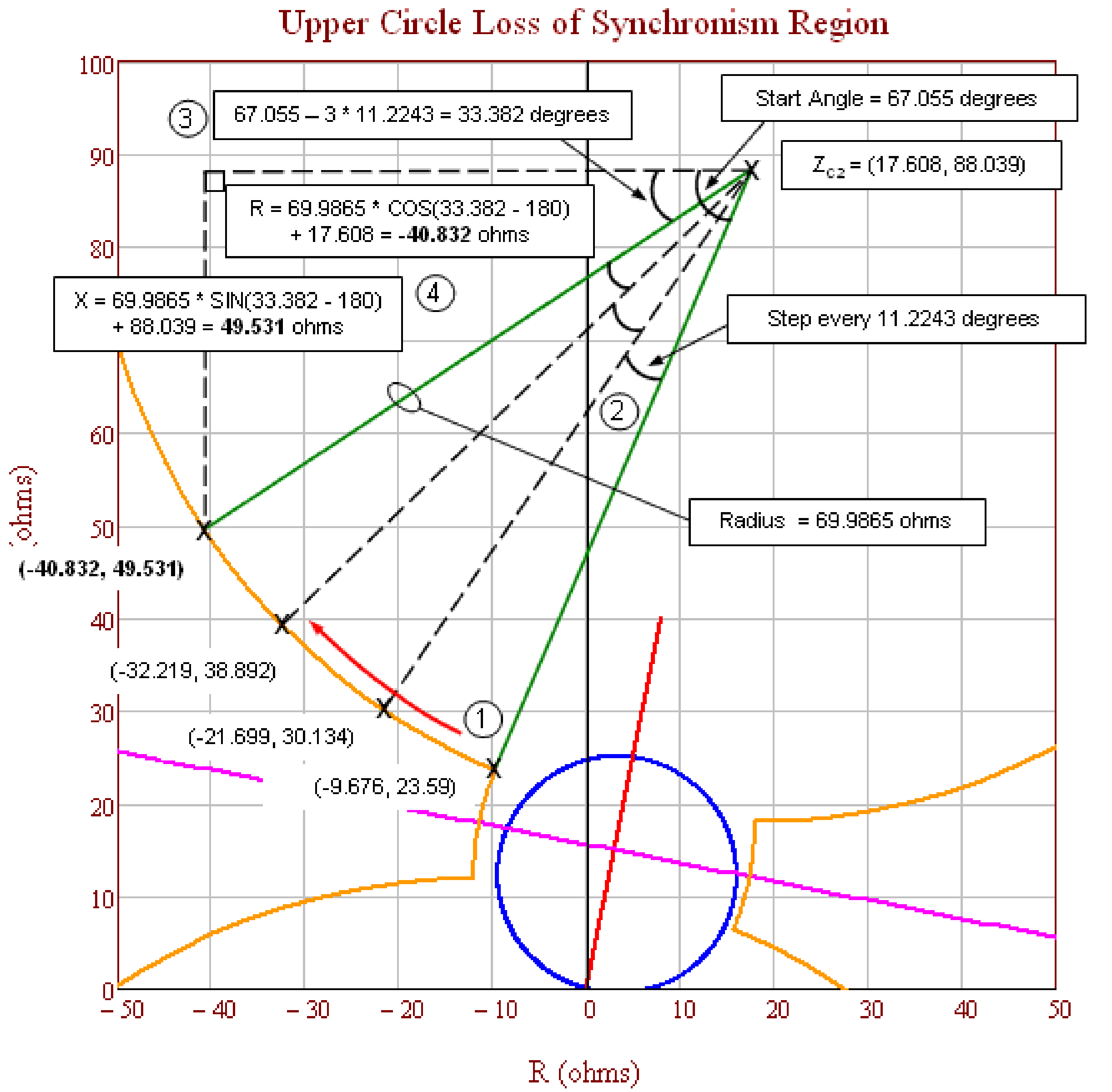

Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-~~1~~2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-~~1~~2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the

maximum power transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-~~1~~ 2 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

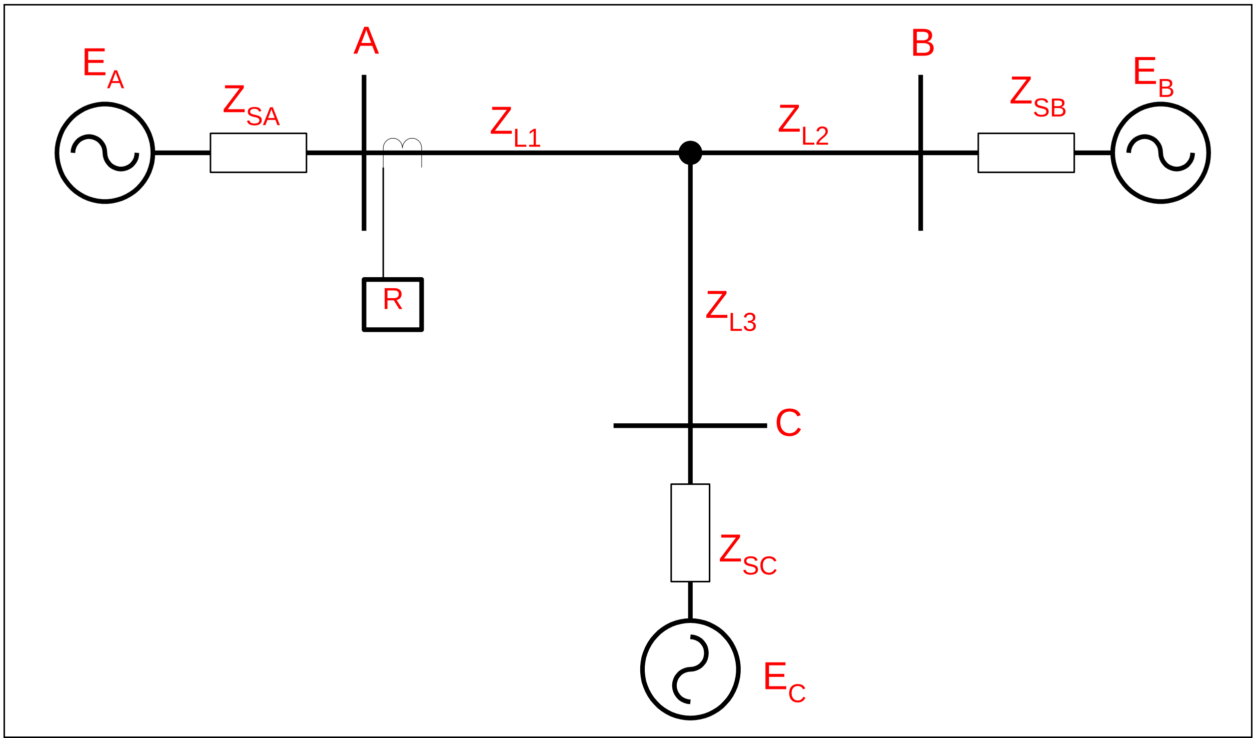

Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

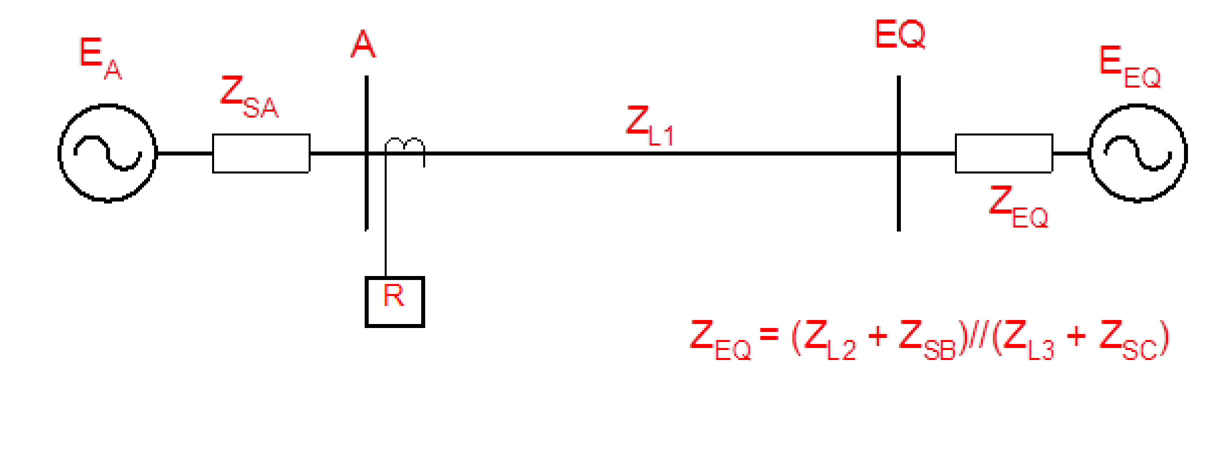

Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-~~1~~2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

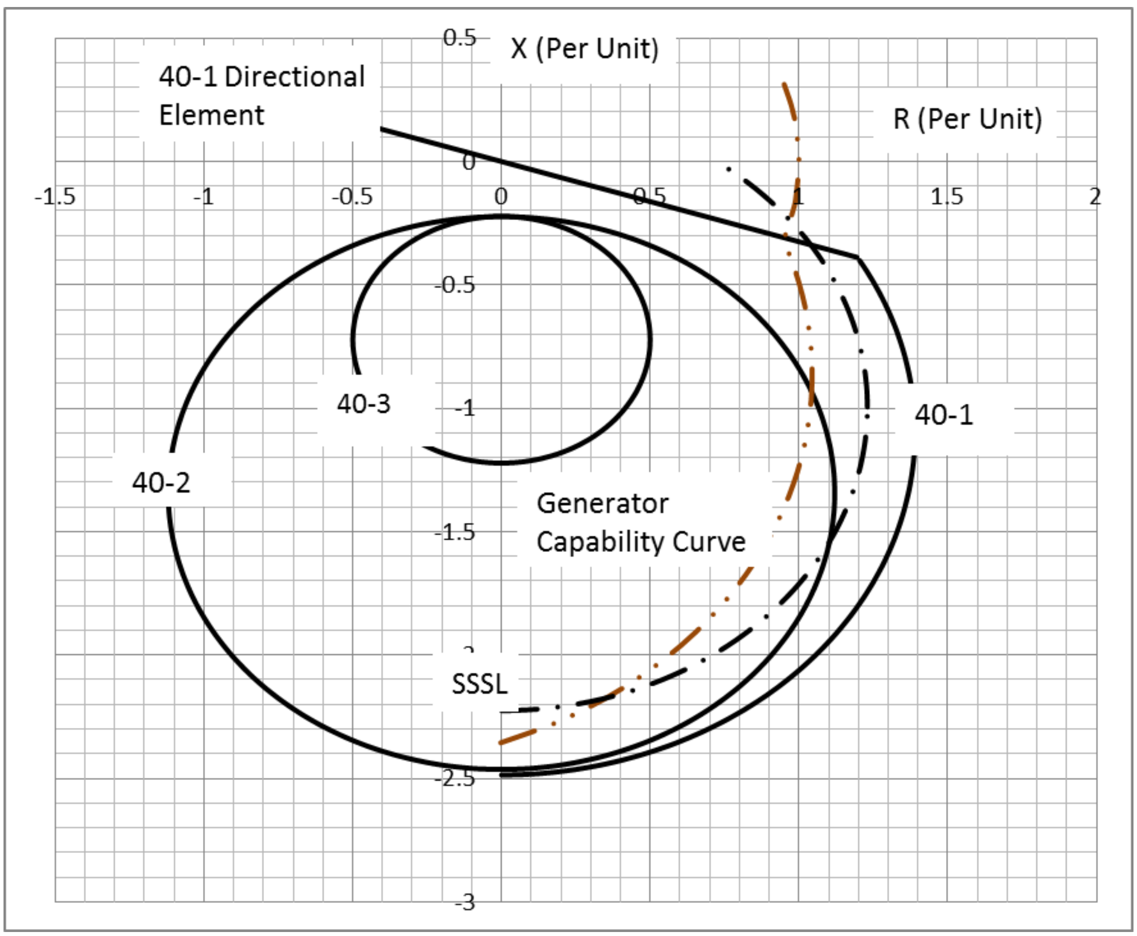

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-~~1~~2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-~~1~~ 2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

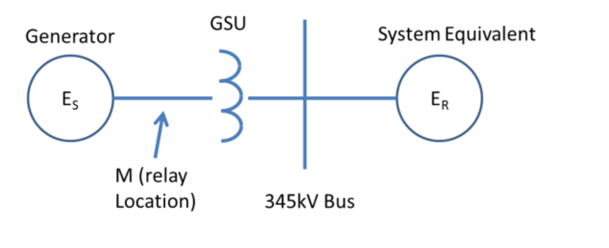

Figure 17: Simple one-line diagram of the system to be evaluated.

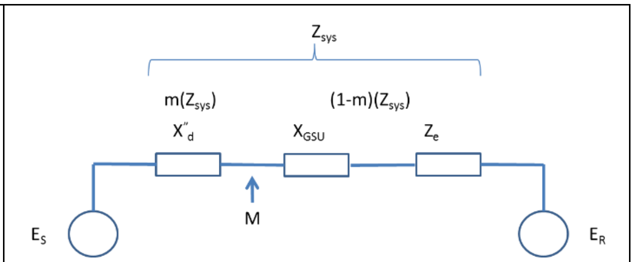

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.						
	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-~~1~~ 2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

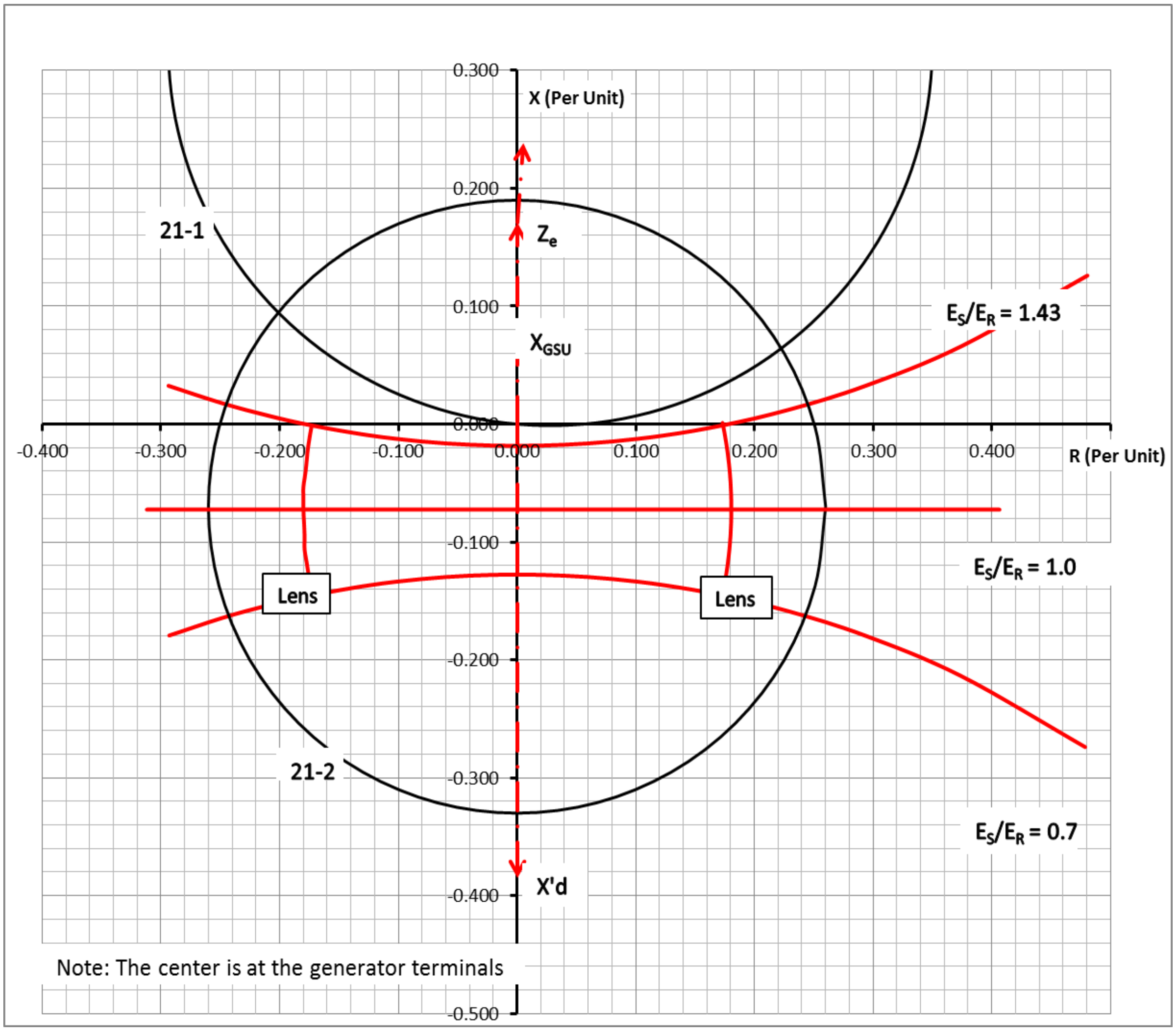

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

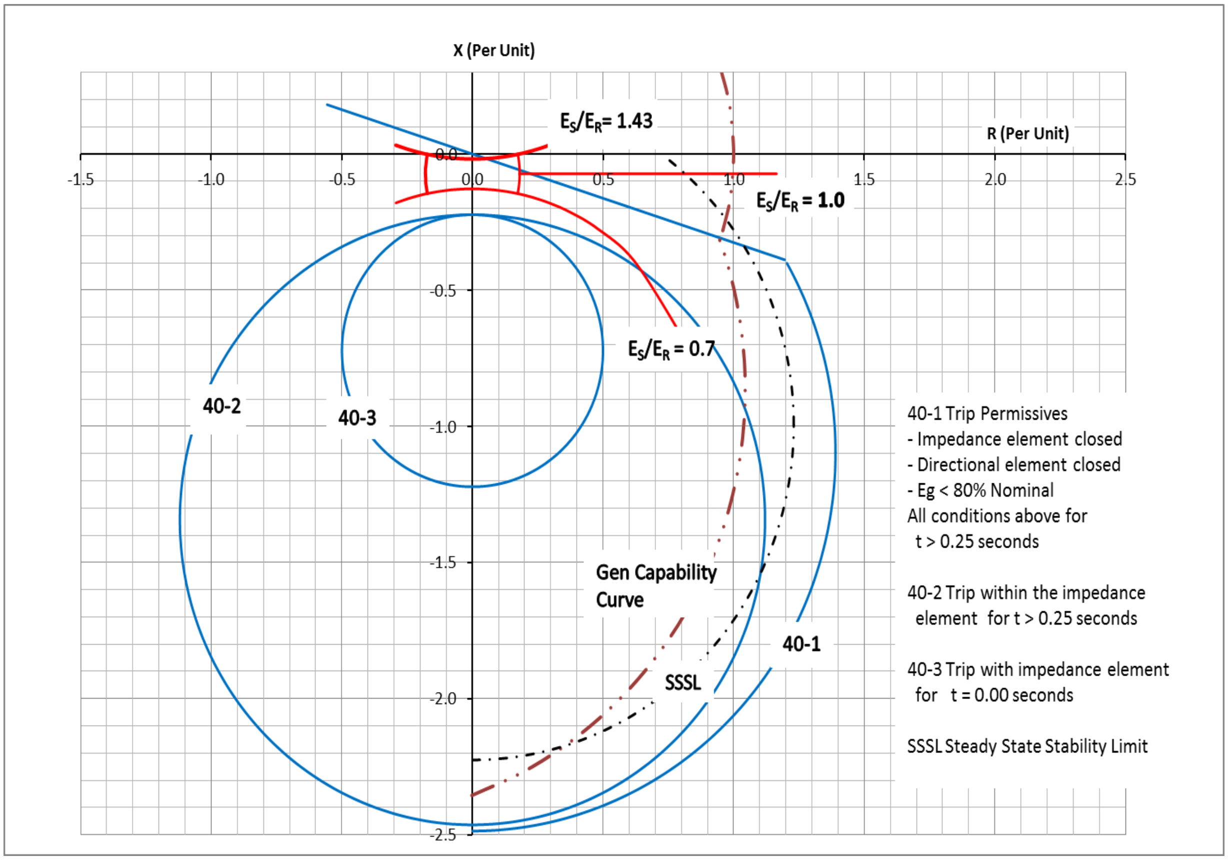

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-~~1~~2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-~~1~~2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-~~1~~ 2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer ($X_{T)}$, and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

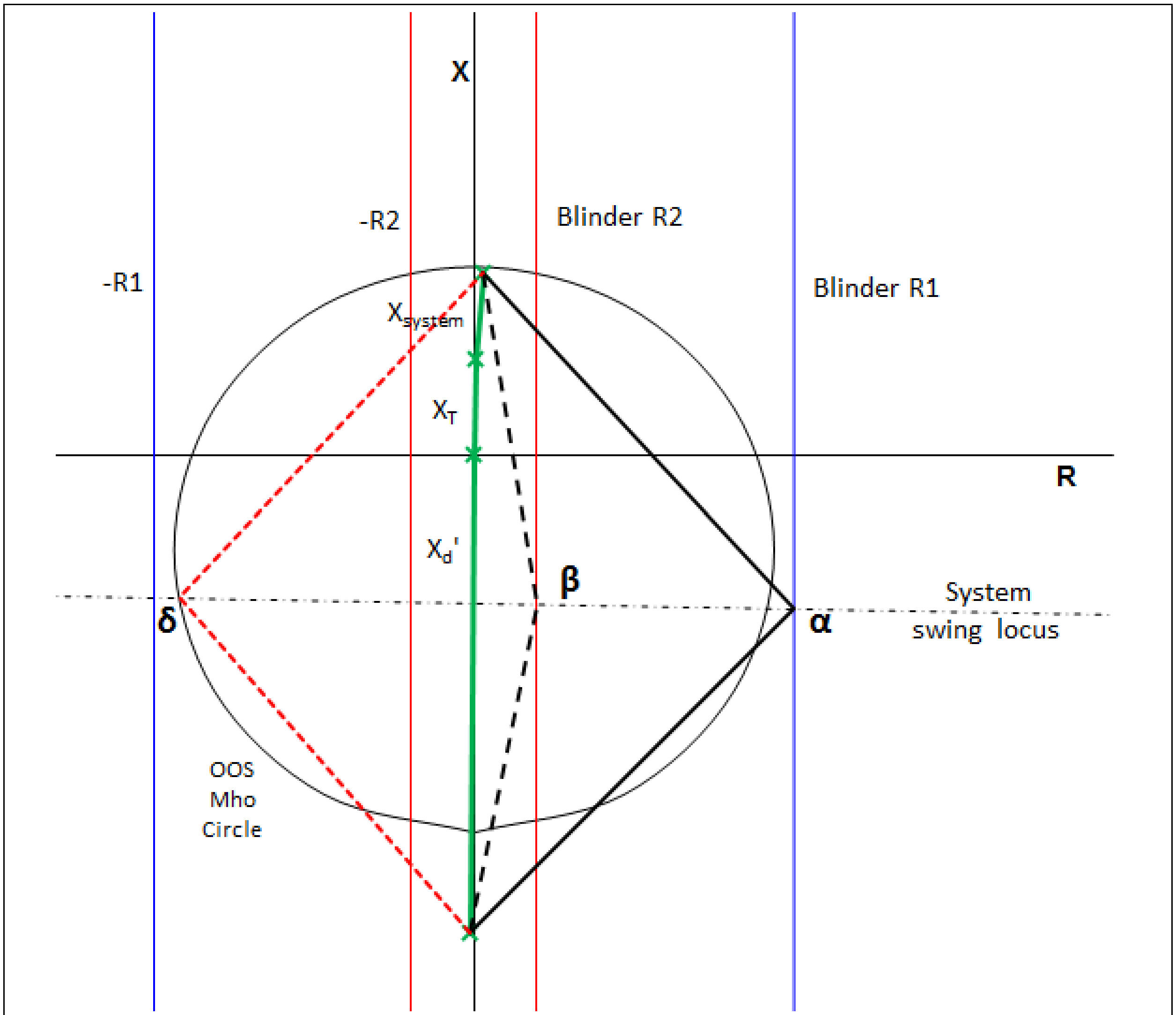

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

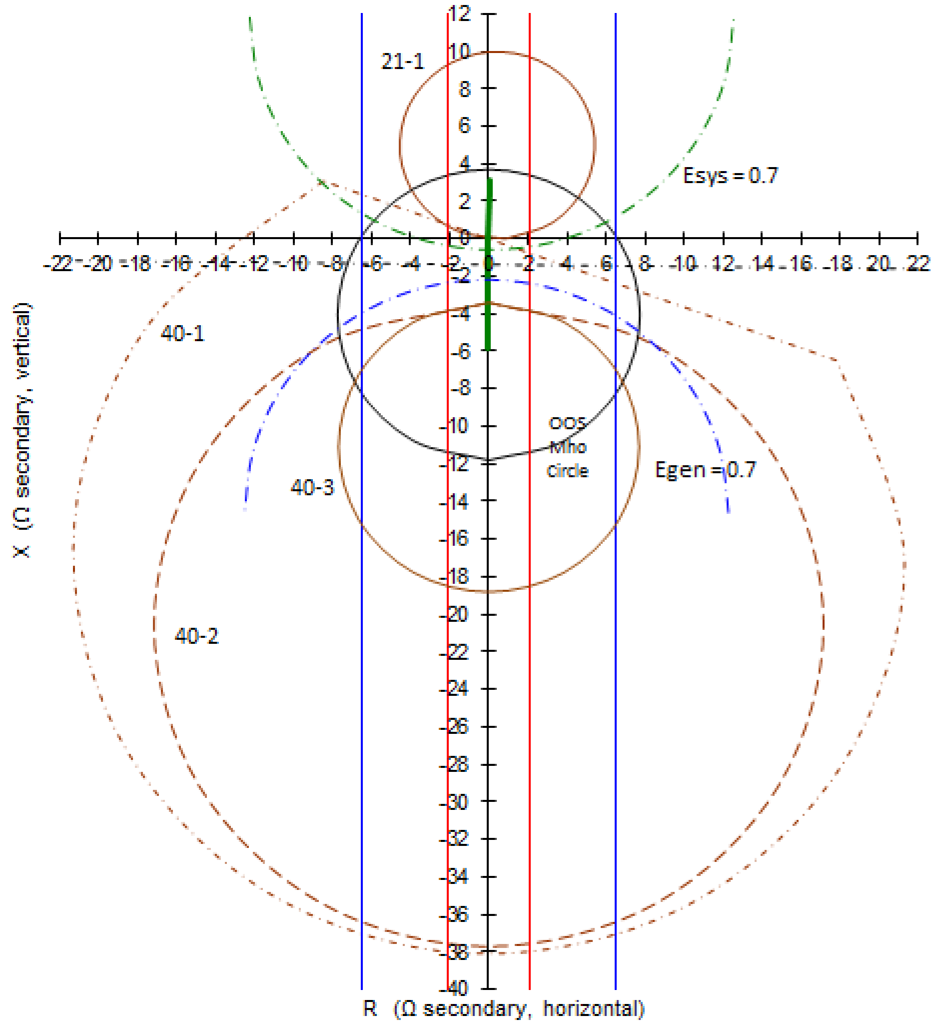

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet ~~PRC-026-1~~PRC-026-2 – Attachment B criteria or can be excluded under the ~~PRC-026-1~~PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet ~~PRC-026-1~~PRC-026-2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets ~~PRC-026-1~~PRC-026-2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under ~~PRC-026-1~~PRC-026-2 – Attachment B criteria.

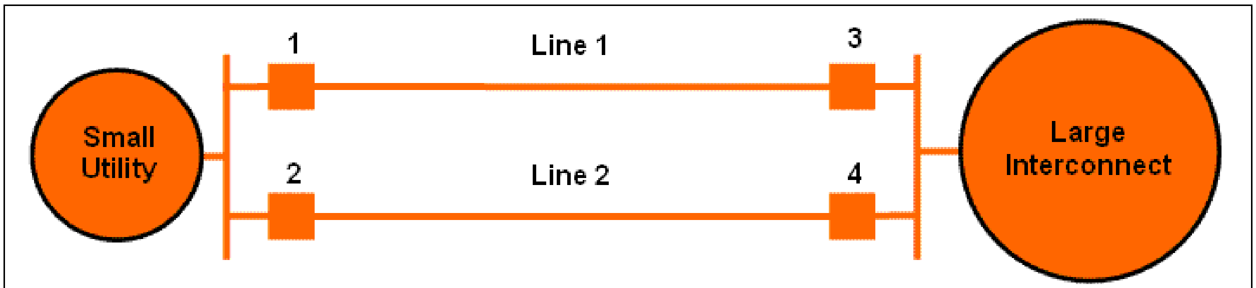

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

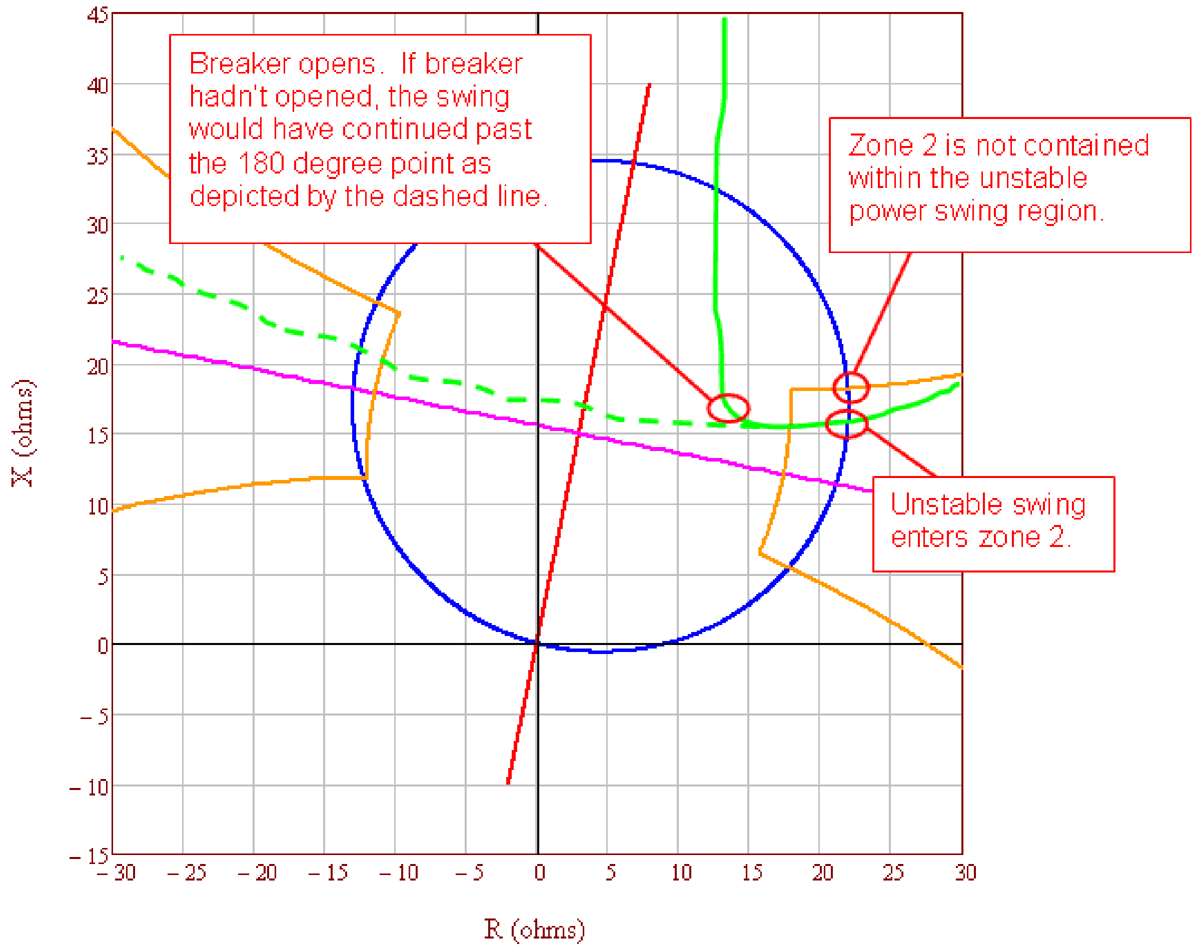

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the ~~PRC-026-1~~PRC-026-2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

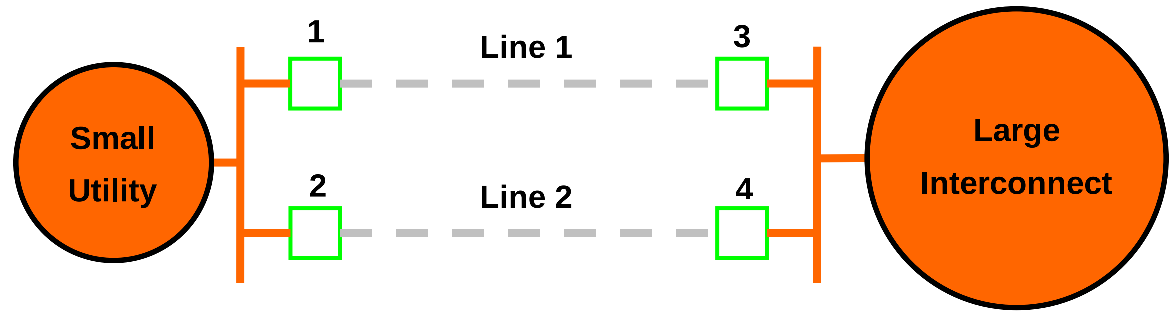

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

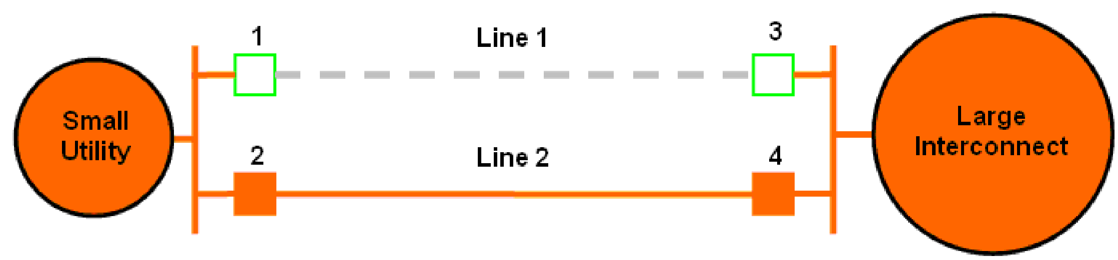

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

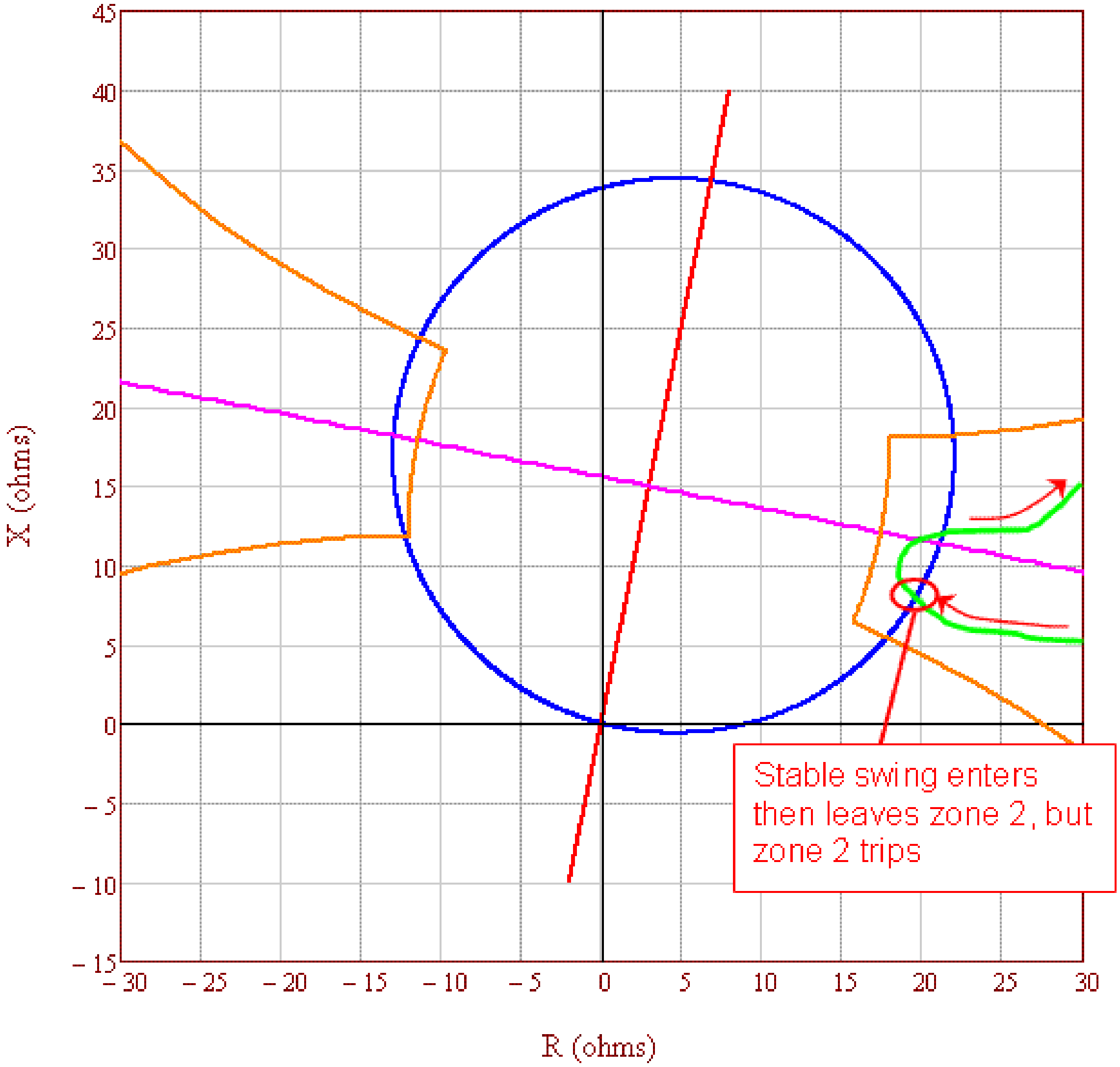

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the ~~PRC-026-1~~PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

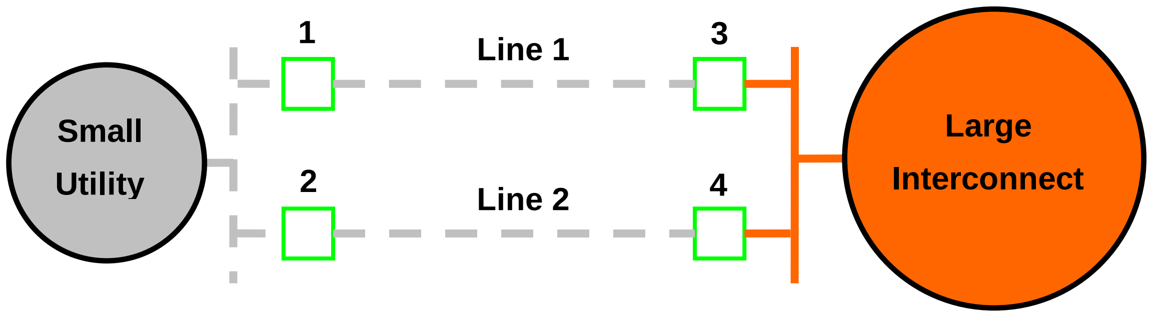

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-~~1~~2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-~~1~~2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-~~1~~2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-~~1~~2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with additional ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
Text

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments

2. **Number:** IRO-008-3

3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.

4. **Applicability**

    4.1. Reliability Coordinator.

5. **Proposed Effective Date:**

    See Implementation Plan.

6. **Background**

    See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator’s Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Coordinator’s Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan,

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL)	when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Area whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the when the System	whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or	within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	TBD	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

Note: The Guidelines and Technical Basis section has not been revised as part of Project 2019-02. A separate technical rationale document has been created to cover Project 2019-02 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.

Standard Development Timeline

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Term(s):
Text

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-~~2~~3
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating ~~Reliability~~ Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authorities.
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time	High	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period,	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations		period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability	Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			within its Wide Area.		Operating Limit (IROL) exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan	its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System	Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability	when the System Operating Limit (SOL) exceedance or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			when the when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	TBD	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

Note: The Guidelines and Technical Basis section has not been revised as part of Project 2019-02. A separate technical rationale document has been created to cover Project 2019-02 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~
~~Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.~~

~~Rationale for R2 and R3:~~
~~Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.~~

~~Rationale for R5 and R6:~~
~~In Requirements R5 and R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18 - 10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None

A. Introduction

Title: Transmission Operations

Number: TOP-001-6

Purpose: To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

Applicability:

1.1. Functional Entities:

4.1.1. Balancing Authority

4.1.2. Transmission Operator

4.1.3. Generator Operator

4.1.4. Distribution Provider

Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two

hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	TBD	Adopted by the Board of Trustees	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/27/18 - 10/17/18

Anticipated Actions	Date
45-day formal comment period with initial ballot	June 2020
10-day final ballot	August 2020
NERC Board adoption	November 2020

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None

A. Introduction

Title: Transmission Operations

Number: TOP-001-~~5~~6

Purpose: To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

Applicability:

1.1. Functional Entities:

4.1.1. Balancing Authority

4.1.2. Transmission Operator

4.1.3. Generator Operator

4.1.4. Distribution Provider

Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**R25.**~~ **M24.** Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated

action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 ~~for three calendar years~~~~rolling~~for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

~~1.4.~~1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	TBD	Adopted by the Board of Trustees	

~~Guidelines and Technical Basis~~

~~None.~~

~~Rationale~~

~~Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.~~

~~Rationale for Requirement R3:~~

~~The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.~~

~~Rationale for Requirement R10:~~

~~New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.~~

~~The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.~~

~~The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.~~

~~The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:~~

- ~~OPA;~~
- ~~Real-time Assessments (RTA);~~

- ~~Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and~~
- ~~Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.~~

~~TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.~~

~~The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.~~

~~Rationale for Requirement R13:~~
~~The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.~~

~~Rationale for Requirement R14:~~
~~The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.~~

~~Rationale for Requirements R16 and R17:~~
~~In response to IERP Report recommendation 3 on authority.~~

~~**Rationale for Requirement R18:**~~

~~Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.~~

~~**Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):**~~

~~[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]~~

~~The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).~~

~~Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.~~

~~The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.~~

~~Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.~~

~~**Rationale for Requirement R21:**~~

~~The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).~~

~~A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data~~

~~exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.~~

~~Rationale for Requirements R22 and R23:~~
~~[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]~~

~~The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).~~

~~Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.~~

~~The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.~~

~~Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.~~

~~Rationale for Requirement R24:~~
~~The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).~~

~~A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.~~

Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** by **8 p.m. Eastern, August 26, 2020.**

Additional information is available on the project page project page. If you have questions, contact Senior Standards Developer, Latrice Harkness, (via email), or at 404-446-9728.

Background Information

The Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. One of the primary objectives of Project 2015-09 is to make changes to the FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards and the revised definitions of Operational Planning Analysis (OPA) and Real-time Assessments (RTA).

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

   ☐ Yes
   ☐ No

   Comments:

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

   ☐ Yes
   ☐ No

   Comments:

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

   Comments:

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

☐ Yes
☐ No

Comments:

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

   Comments:

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

   Comments:

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

   ☐ Yes
   ☐ No

   Comments:

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Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT's proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-014-3, Requirement R7 is intended to provide a mechanism for Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL methodology. FAC-014-3, Requirement R7 addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. Therefore, this requirement focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process required in FAC-014-3 Requirement R7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don't use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement R8 requires PCs and TPs to communicate pertinent information on Corrective Action Plans (CAP) developed to address any instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon to the RC and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R7 and R8 of FAC-014-3, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL methodology (FAC-011-4). Furthermore, potentially critical stability information is communicated by planners to operators resulting an improvement in reliability by increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)
1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)
1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)
1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.
1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:
1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:
- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R1. The Planning Authority shall have a documented SOL methodology for use in developing SOLs within its Planning Authority Area. This SOL methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-014-3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).

R2.	The Planning Authority's SOL methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

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R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1:** **Note: 'b'**	
R2.3.2. System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1:** **Note: 'e'**	
R2.4. To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1:** **Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

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	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2. Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3. Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4. Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4. The Planning Authority shall issue its SOL methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard."
R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

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Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of ~~a new FAC-015-1 Reliability Standard and~~ revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT's ~~proposal for a new FAC-015-1 Reliability Standard, along with the~~ proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL ~~M~~methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-01~~5~~4-~~1~~3, Requirement~~s~~ ~~R1~~ R7 ~~– R3 ensure~~is intended to provide a mechanism for ~~that~~ Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL ~~M~~methodology. FAC-~~015~~014-~~1~~3, Requirement~~s~~ R~~1 – R3~~7 ~~respectively~~ addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. ~~These~~ Therefore, this requirement~~s~~ focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process~~es~~ required in FAC-~~015~~014-~~1~~ 3 Requirement~~s~~ R~~1 – R3~~7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don't use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL ~~M~~methodology.

FAC-~~015~~014-~~1~~3, Requirement ~~R4~~ R8 requires PCs and TPs to communicate ~~any~~ pertinent information on Corrective Action Plans (CAP) developed to address any instability~~, Cascading or uncontrolled separation, along with key supporting information,~~ identified in ~~the~~ Planning Assessments of the Near-Term Transmission Planning Horizon to the RC~~s~~ and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements ~~R1~~ R7 ~~–~~and R~~4~~8 of FAC-014-3~~5~~, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL ~~M~~methodology (FAC-011-4~~ & FAC-014-3~~). Furthermore, potentially critical stability information is communicated by planners to operators resulting ~~. The result is~~ an improvement in reliability by ~~ensuring~~ increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)
1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:
1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)
1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)
1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.
1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:
1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:
- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R1. The Planning Authority shall have a documented SOL ~~M~~methodology for use in developing SOLs within its Planning Authority Area. This SOL ~~M~~methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-~~015~~014-~~1~~ 3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

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	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

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	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
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	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

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		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL ~~M~~methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via ~~FAC- 015-1, Requirement R4. IROLs are established by the RC as required by FAC-014-3.~~the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability

		Operating Limit (IROL).
R2. The Planning Authority's SOL ~~M~~methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
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performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

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R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

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	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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	all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL ~~M~~methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as “Requirements Recommended for Retirement” in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as “More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

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	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard."
R4.3. Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL methodology) within its Reliability Coordinator Area. This SOL methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R7 and Part 7.1. R7. Each Reliability Coordinator shall include in its SOL methodology 7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	011-4, Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: 6.1. System performance for no Contingencies	The items in approved FAC-011-3, Requirement R2.1 and R2.2 are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposedTOP-001-5 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.4 divide system performance requirements for the no contingency state (N-0) into each of the

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	demonstrates the following: 6.1.1. Steady State flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings. 6.1.2. Steady State voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when	three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in

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	System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded. 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. System performance for the single Contingencies listed in Part 5.1.	Part 6.2.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly identify that, in determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is an acceptable only after all other available System adjustments have been made. TOP-001-5, Requirement R25 and IRO-008-3, Requirement R7 support FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to determine SOL

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	demonstrates the following: 6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady State post-Contingency voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met. 6.2.4. Instability, Cascading or uncontrolled	exceedances in accordance with its RC's the SOL methodology.

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	separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. System Performance for applicable Contingencies identified in Part 5.2 demonstrates that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	

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	TOP-001-5, Requirement R25. R25. Each Transmission Operator shall use the applicable RC's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.. IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	FAC-011-4, Requirement R5, Part 5.1 5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4 Requirement R5, Part 5.1. FAC-011-4 Requirement R5, Part 5.1. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance

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R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	• generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; and	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs

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time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas,	and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is “studied” at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL methodology to describe the allowed uses

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	necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.	of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed

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	2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-002-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as	retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made. Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is

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	performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system.

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	The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.4 albeit with improved language for clarity. FAC-011-4 Requirement R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: R6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following,	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5.

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along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized

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		stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.1. Specify the following single Contingency events5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any. 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.	FAC-011-4, Requirement R5, Part 5.3 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology shall:	FAC-011-4, Requirement R5, Part 5.3 and FAC-014-3 Requirement R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-014-3, Requirement R7, the Planning Coordinator is required to identify and annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term

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R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits. FAC-014-3 Requirement R7: R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include: 7.1. A requirement that the following SOL exceedances will always be communicated, within a	Transmission Planning Horizon, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.3 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	timeframe identified by the Reliability Coordinator. 7.1.1. IROL exceedances; 7.1.2. SOL exceedances of stability limits; 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation; 7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and 7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.	

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	7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator. 7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and 7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL methodology shall include] Anticipated transmission system	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL methodology the method	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4.

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configuration, generation dispatch and Load level	for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; <u>TOP-002-4, Requirement R1</u>: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). <u>IRO-008-2, Requirement R1</u>: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.	Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-

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	Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement R8, Part 8.2 R8.2 Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R8, Part 8.2.

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FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL methodology and any changes to that methodology, prior to the effectiveness of the methodology or of a change to the methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4: R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within an Interconnection 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL methodology within 30 days of the request if they indicate a reliability-related need for it. 8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL methodology to] Each Planning Authority and Transmission	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2.	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs

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Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	R9. Each Reliability Coordinator shall provide its SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	and TPs that are responsible for planning within the RC Area rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area.	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

Mapping Document

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL ~~M~~methodology) within its Reliability Coordinator Area. This SOL ~~M~~methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL ~~M~~methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL ~~M~~methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL ~~M~~methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL ~~M~~methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R7 and Part 7.1. R7. Each Reliability Coordinator shall include in its SOL ~~M~~methodology 7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL ~~M~~methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	011-4, Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~:	The items in approved FAC-011-3, Requirement R2.1 and R2.2 ~~are addressed~~are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposed ~~FAC-014-3 R7R6~~TOP-001-5 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.~~3~~ 4 divide system performance requirements for the ~~pre-~~no

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	6.1. ~~The~~ System performance for no ~~actual pre-~~ Contingencies~~y~~ ~~state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following: 6.1.1. Steady State f~~F~~low through Facilities are within Normal Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time	contingency state (N-0) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.~~3~~4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.~~3~~ 4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and

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	duration of those Emergency Ratings. 6.1.2. Steady State ~~V~~voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded.	uncontrolled separation were included in Part 6.2.~~3~~4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly ~~delineate the system performance requirements related to establishing stability limits using the Contingencies identified in Requirement R5, Part 5.3~~identify that, in determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is ~~a~~an acceptable only after all other available System adjustments have been made.

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	~~6.1.3.~~6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. ~~The evaluation of~~ System performance for the ~~potential~~ single Contingencies listed in Part 5.1.~~1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following: 6.2.1. Steady State post-Contingency ~~F~~flow through Facilities ~~are~~	TOP~~FAC~~-001~~1~~4-5~~3~~, Requirement R~~7~~25 and IRO-008-3, Requirement R7~~6~~ support~~s~~ FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to ~~use the performance criteria identified~~determine SOL exceedances in accordance with its RC's the SOL ~~M~~methodology.

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	within applicable Emergency Ratings~~, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings~~. Flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady State post-Contingency ~~V~~voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL	

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	~~M~~methodology are met. ~~6.2.3.~~6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. ~~The evaluation of~~ System Performance for applicable ~~the potential~~ Contingencies identified in Part 5.2 ~~against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates that instability, Cascading, or uncontrolled separation	

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	that adversely impact the reliability of the Bulk Electric System does not occur. ~~6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.~~ 6.~~5~~ 4 In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made. ~~FAC~~TOP-001~~14~~-5~~3~~, Requirement R25~~67~~. R~~6~~25 ~~7~~. Each Transmission Operator shall use the applicable RC's SOL methodology when determining SOL exceedances for Real-time	

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	Assessments, Real-time Monitoring, and Operational Planning Analysis.~~Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances in accordance with its Reliability Coordinator's SOL Methodology when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~. IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.	

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FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1~~.1~~ 5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4 Requirement R5, Part 5.1~~.1~~. FAC-011-4 Requirement R5, Part 5.1~~.1~~. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4.	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that

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R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. ~~unit~~ angular stability; and 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability	are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). ~~If SOL exceedance is occurring, the system is not performing reliably.~~ Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new

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	Coordinator Area or other Reliability Coordinator Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.	operating state is "studied" at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL ~~M~~methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into

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	The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: ~~1. FAC-014-3, Requirement R8: In addressing any potential or actual SOL exceedances, each Reliability Coordinator and Transmission Operator shall allow for Non-Consequential Load Loss within their Operating Plan only if all other means of System adjustments have been exhausted to prevent:~~ ~~• equipment damage, or~~ ~~• instability, Cascading, uncontrolled separation~~ ~~4.~~1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of	consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.~~5~~ 4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as

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	its Operational Planning Analysis as required in Requirement R1. ~~5.~~2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). ~~6.~~3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. ~~7.~~4. TOP-~~012~~002-~~3~~4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. ~~8.~~5. IRO-008-~~2~~3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating	well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made. Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

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	Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. ~~9.~~6. IRO-008-~~2~~3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). ~~10.~~7. IRO-008-~~2~~3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL ~~M~~methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.~~5~~4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.

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	Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.~~5~~ 4 albeit with improved language for clarity. FAC-011-4 Requirement R6. Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~: R~~.~~6.~~5~~ 4 In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	

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FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4).

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		FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL ~~M~~methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)~~ for the area under study~~. The SOL ~~M~~methodology for each set shall: 5.1. Specify the following single Contingency events~~ for use in determining stability limits and performing OPAs and~~	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	~~RTAs:~~5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. ~~Identify any~~Specify additional single or multiple Contingency events or types of Contingency events, if any ~~for use in performing OPAs and RTAs~~. ~~5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.~~ 5.~~4~~3. Describe the method(s) for identifying which, if any, of the Contingency	

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	events provided by the Planning Coordinator in accordance with FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, to use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL ~~M~~methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	FAC-011-4, Requirement R5, Part 5.~~4~~3 R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) ~~for the area under study~~. The SOL ~~M~~methodology shall: 5.~~4~~3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, to use in determining stability limits. FAC-~~015~~014-~~1~~ 3 Requirement ~~R4~~R7:	FAC-011-4, Requirement R5, Part 5.~~4~~ 3 and FAC-~~015~~014-~~1~~ 3 Requirement ~~R4~~ R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, the Planning Coordinator is required to identify and annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon~~any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R4~~, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.~~4~~ 3 for considering

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	R7. ~~R4.~~ Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include: 7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator. 7.1.1. IROL exceedances; 7.1.2. SOL exceedances of stability limits;	those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation; 7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and 7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits. 7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator. 7.2.1. Post-contingency SOL exceedances of Facility	

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	Ratings and emergency System Voltage limits, and 7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits. ~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~ ~~4.2 The associated stability criteria used as part of determining the instability;~~ ~~4.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;~~ ~~4.4 A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified;~~	

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	~~4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and~~ ~~4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL ~~M~~methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL ~~M~~methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL ~~M~~methodology shall include] Anticipated transmission system	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4.

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configuration, generation dispatch and Load level	method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.	Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a “study” or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-

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	Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL ~~M~~methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement ~~R7~~R8, Part ~~7~~8.2 ~~R6~~R8.2 Criteria for determining when ~~violating~~ exceeding a SOL qualifies as ~~an~~ exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement ~~R7~~R8, Part ~~7~~8.2.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL ~~M~~methodology and any changes to that methodology, prior to the effectiveness of the ~~M~~methodology or of a change to the ~~M~~methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4: R9. Each Reliability Coordinator shall provide its new or revised SOL ~~M~~methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within an Interconnection 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's ~~M~~methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL ~~M~~methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL ~~M~~methodology within 30 days of the request if they indicate a reliability-related need for it. ~~Part 9.2 also includes a requirement to provide the SOL Methodology as soon as practicable if a change was necessary to address a reliability issue. This provides flexibility for~~

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		~~an RC to make reliability needed changes to its SOL Methodology quickly.~~8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL ~~M~~methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2. R9. Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL ~~M~~methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL ~~M~~methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology:	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	9.2.3 Each Transmission Operator within its Reliability Coordinator Area.	

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
<u>FAC-014-2, Requirements R3 and R4</u> R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 <u>FAC-011-4, Requirement R9, Part 9.2:</u> **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

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	planning any portion of the Reliability Coordinator Area; FAC-014-3 Requirement R6: **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
FAC-014-2, Requirement R5, R5.1 R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) FAC-014-3, Requirement R5: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning	

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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:	

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	1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-

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	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-014-3, Requirements R7 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning

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and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g.	Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

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	violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. MOD-028-2, Requirement **R7**: **R7**. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: **R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations. **R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement **R4:** **R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the	With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement **R2.6**: **R2.6.** [The TOP shall…] Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	

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FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-014-3, Requirement R7 (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all

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		instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL m~~M~~ethodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology (SOL ~~M~~methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology. R4. Each Reliability Coordinator shall establish stability limits ~~to be used in operations~~ when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL ~~M~~methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL ~~M~~methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL ~~M~~methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because

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		the RC did not ensure that the TOP's SOL was consistent with its SOL ~~M~~methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly

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Coordinator Area that are consistent with its Reliability Coordinator's SOL ~~M~~methodology.	with its Reliability Coordinator's SOL ~~M~~methodology.	understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL ~~M~~methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL ~~M~~methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL ~~M~~methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3~~015-1~~, Requirement~~s~~ ~~R7~~R6 ~~R1 – R3~~ FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: ~~*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*~~ **9.2** Each of the following entities ~~30 days~~ prior to the effective date of the SOL methodology ~~or as soon as practicable if a change must be~~	The SDT is proposing a construct that does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL ~~M~~methodology. The PCs and T~~O~~Ps responsible for planning any portion of the RC's Area are made aware of the RC's SOL ~~M~~methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL ~~M~~methodology, PCs and TPs who plan any portion of the System in the

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	~~implemented in less than 30 days to address a reliability issue~~: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area; FAC-014-3~~015-1~~ Requirement R7~~6~~~~R1 – R3~~: **R~~7~~6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to ~~use Facility~~use Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described ~~in its~~in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for	RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. ~~New Reliability Standard FAC-015-1 along with the changes in the P~~proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3~~015-1~~, Requirement~~s~~ R76 ~~R1 – R3~~ ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those ~~established in accordance~~ described within the RC's SOL ~~M~~methodology. ~~FAC-015-1, Requirement R1 addresses Facility Ratings, Requirement R2 addresses the System steady state voltage limits, and Requirement R3~~

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	any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator. ~~1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~	~~addresses the stability performance criteria used in Planning Assessments. These requirements~~ FAC-014-3, Requirement R~~7~~6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability. ~~By implementing Requirements R1 – R3 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations.~~

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	~~• The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan,~~ ~~• Facility Rating differences are due to variations in ambient temperature assumptions,~~ ~~• The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator, or~~ ~~• The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.~~ ~~2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability~~	

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	~~Coordinator's SOL Methodology. The process may allow the use of less limiting System steady-state voltage limits if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ • ~~The Planning Coordinator provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Planning Coordinator and Reliability Coordinator.~~ ~~**3.** Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. The~~	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~process may allow the use of less limiting stability performance criteria if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ • ~~The Planning Coordinator provides a technical rationale for using a less limiting stability performance criterion to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provides a technical rationale for using a less limiting stability performance criterion to each affected Planning Coordinator and Reliability Coordinator.~~	
FAC-014-2, Requirement R5, R5.1 R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities)	~~Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1.~~ While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3,

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includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information: R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) FAC-014-3, Requirement R5: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies);	Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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	5.2.5. A description of ~~the associated~~ system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.~~5~~ 6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested	

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	SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. IRO-014-3, Requirement R1 R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	

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<u>FAC-014-2, Requirement R5, R5.2</u> R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 <u>FAC-014-3, Requirement R3</u> R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator~~ in accordance with its Reliability Coordinator's SOL Methodology~~. <u>MOD-028-2, Requirement R7:</u> R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. <u>MOD-029-2a, Requirement R4:</u> R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.~~ The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states:~~ ~~R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).~~ The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate

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	for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	1. FAC-014-3~~015-1~~, Requirements ~~R7, R8R6,~~ R7 ~~R1 – R4~~ 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-014-3~~015-1~~ Requirements ~~R76,~~ R~~8~~7 ~~**R1 – R3**~~ (Also ~~S~~see the t~~T~~ranslation above for Requirements R3 and R4~~ section above.~~) **R7.** Each Planning Coordinator and each Transmission Planner shall annually(?) communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability	Provision of important planning study information to TOPs and RCs is preserved in ~~Reference the Ddescription and Change Justification above for Requirements R3 and R4, which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-014-3015-1, R7.~~ ~~FAC-014-3015-1, Requirements R76 R1 – R3 results in PCs and TPs using Facility Ratings, System steady state voltage limits criteria, and stability performance criteria in their Planning Assessments of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the crtieria for Facility Ratings, System Voltage Limits, and~~

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.	~~stability performance criteria established in accordance described within in the RC's SOL Methodology.~~ FAC-014-3~~015-1~~, Requirement R7, which~~4~~ requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability ~~, Cascading or uncontrolled separation~~ identified in ~~the~~ its Planning Assessments ~~and Transfer Capability assessments~~ to each impacted ~~RCs, TOPs, TOs, and GOs~~ TOP and RC. The subparts of Requirement R7~~4~~ require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. ~~This information is also necessarily communicated to TOs and GOs for their use in identifying Facilities that require higher levels of vegetative management or cyber protection.~~ The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather,

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~**R4.** Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include:~~ ~~**4.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~ ~~**4.2** The associated stability criteria used as part of determining the instability;~~ ~~**4.3** The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;~~ ~~**4.4** A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified;~~ ~~**4.5** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action,~~	TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;~~ ~~**4.6** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~ MOD-028-2, Requirement **R7**: **R7**. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: **R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations. **R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement **R4:** **R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the	

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	assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement **R2.6**: **R2.6.** [The TOP shall…] Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-014-3~~015-1~~, Requirement ~~R4~~ ~~R8~~R7 (See the Translation above for Requirements R5.3 and R5.4 ~~section above.~~)	FAC-014-3~~015-1~~, Requirement ~~R6~~ R~~8~~7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7 addresses not only the identification of multiple contingencies that result in stability criteria violation ~~limits~~, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7 ensures the type of instability, ~~relevant~~ the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation ~~assumptions used by the PC~~ are communicated by the PC to the appropriate TOP and RC.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		• ~~Additionally, FAC-015-1, Requirement R4 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation.~~ • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3~~015-1~~, Requirement ~~R4~~ R87 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC ~~in accordance with FAC-015-1, Requirement R4~~. ~~In addition~~Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3~~015-1~~, Requirement ~~R4s~~ R87 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has

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		not identified any instability and therefore has nothing to communicate.

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Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
IRO-008-2, Requirement R1	IRO-008-3, Requirement R1	No modifications made.
IRO-008-2, Requirement R2	IRO-008-3, Requirement R2	No modifications made.
IRO-008-2, Requirement R3	IRO-008-3, Requirement R3	No modifications made.
IRO-008-2, Requirement R4	IRO-008-3, Requirement R4	No modifications made.
IRO-008-2, Requirement R5 **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a	IRO-008-3, Requirement R5 **R5.** Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments

Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*	actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*	must be communicated and if so, with what priority. This will ensure communication consistency regarding SOL exceedances within an RC's area between the RC and its TOPs. Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.
IRO-008-2, Requirement R6 Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*	IRO-008-3, Requirement R6 Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor:*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency regarding SOL exceedances within an RC's area between the RC and its

Standard IRO-008-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Medium] [Time Horizon: Same-Day Operations, Real-time Operations]	TOPs. Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.

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Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R1	TOP-001-6, Requirement R1	No modifications made.
TOP-001-5, Requirement R2	TOP-001-6, Requirement R2	No modifications made.
TOP-001-5, Requirement R3	TOP-001-6, Requirement R3	No modifications made.
TOP-001-5, Requirement R4	TOP-001-6, Requirement R4	No modifications made.
TOP-001-5, Requirement R5	TOP-001-6, Requirement R5	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R6	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R7	No modifications made.
TOP-001-5, Requirement R8	TOP-001-6, Requirement R8	No modifications made.
TOP-001-5, Requirement R9	TOP-001-6, Requirement R9	No modifications made.
TOP-001-5, Requirement R10	TOP-001-6, Requirement R10	No modifications made.
TOP-001-5, Requirement R11	TOP-001-6, Requirement R11	No modifications made.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R12	TOP-001-6, Requirement R12	No modifications made.
TOP-001-5, Requirement R13	TOP-001-6, Requirement R13	No modifications made.
TOP-001-5, Requirement R14	TOP-001-6, Requirement R14	No modifications made.
TOP-001-5, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	TOP-001-6, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency on SOL exceedances within an RC's area between the RC and its TOPs. This communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output to operator to operator communications.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.
TOP-001-5, Requirement R16	TOP-001-6, Requirement R16	No modifications made.
TOP-001-5, Requirement R17	TOP-001-6, Requirement R17	No modifications made.
TOP-001-5, Requirement R18	TOP-001-6, Requirement R18	No modifications made.
TOP-001-5, Requirement R19	TOP-001-6, Requirement R19	No modifications made.
TOP-001-5, Requirement R20	TOP-001-6, Requirement R20	No modifications made.
TOP-001-5, Requirement R21	TOP-001-6, Requirement R21	No modifications made.
TOP-001-5, Requirement R22	TOP-001-6, Requirement R22	No modifications made.
TOP-001-5, Requirement R23	TOP-001-6, Requirement R23	No modifications made.
TOP-001-5, Requirement R24	TOP-001-6, Requirement R24	No modifications made.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R6 and Requirement R8 which requires performance framework and description of identifying Interconnection Reliability Operating Limits (IROLs) within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to include a requirement for Part 7.2.	The Reliability Coordinator failed to include a requirement for Part 7.1.	The Reliability Coordinator failed to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.5. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL ~~M~~methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 ~~or 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, ~~or 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL ~~M~~methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3~~, and 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance ~~criteria~~ framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R6 and Requirement R8 which requires performance framework and description of identifying Interconnection Reliability Operating Limits (IROLs) within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

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VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to include a requirement for Part 7.2.	The Reliability Coordinator failed to include a requirement for Part 7.1.	The Reliability ~~Cooridnator~~Coordinator failed to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R~~7~~8	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R~~7~~8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part ~~7~~8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (criteria for developing any associated IROL T_v) in its SOL ~~M~~methodology.	The Reliability Coordinator failed to include Parts ~~7~~8.1 and ~~7~~8.2 in its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R~~7~~8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.~~7~~5. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~VRF Justifications for FAC-011-4 Requirement R8~~	
~~**Proposed VRF**~~	~~**Medium**~~
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements (Parts) so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~VSLs for FAC-011-4, Requirement R8~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.~~	~~The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.~~

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~~VSL Justifications for FAC-011-4, Requirement R8~~	
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (“SOL methodology”) as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**Medium**
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	**Medium**

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology (“SOL ~~M~~methodology”) as established in FAC-011-4.

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VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.~~6~~5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.~~6~~5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	Medium~~High~~
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~mingle More than One Obligation~~	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria. ~~N/A~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	Medium

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement ~~R5.3 and~~R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	Medium

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 -and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in IRO-008. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for IRO-008-3, Requirement R1

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R1

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R2

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R2

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R3

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R3

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R4

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R4

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R5

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R5

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R6
The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R6
The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	The requirement contains one objective, therefore a single VRF is assigned.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for IRO-008-3, R7			
Lower	**Moderate**	**High**	**Severe**
			The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TOP-001-6, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R1

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R2

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R3

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R4

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R5

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R6
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R7
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R8
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R9
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R10
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R19
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R19
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R22
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R22
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for TOP-001-6, R25			
Lower	**Moderate**	**High**	**Severe**
			The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Technical Rationale for Reliability Standard FAC-011-4

June 2020

FAC-011-4 – System Operating Limits Methodology for the Operations Horizon

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires the SOL methodology "be applicable for developing System Operating Limits (SOLs) used in the operations horizon." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings." Facility Ratings to be used in operations as SOLs are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs." This language is preserved in Requirement R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL methodology, and

2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between RCs and their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1.** Require that BES bus/station have an associated System Voltage Limit, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
- **3.2.** Require that System Voltage Limits respect voltage-based Facility Ratings;
- **3.3.** Require that System Voltage Limits are greater than or equal to in-service BES relay settings for under-voltage load shedding systems and Undervoltage Load Shedding Programs;
- **3.4.** Identify the lowest allowable System Voltage Limit;
- **3.5.** Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection;

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its RC Area for voltage-based Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of “System Voltage Limits”, both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Part 3.5requires that the SOL methodology define a method for determining common System Voltage Limits between RCs and TOPs. RC and TOPs may independently identify System Voltage Limits which if not coordinated could create reliability issues. An example could be where one TOP A chooses very wide System Voltage Limits on its equipment but TOP B could have much tighter System Voltage Limits even within the same substation. TOP A may operate equipment that are within its System Voltage Limits but cause an exceedance of TOP B’s equipment. Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL methodology shall ensure System Voltage Limits are not set at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of System damping.

Also included in Part 4.1 is language requiring the SOL methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations. Many stability tools will consider a subset of contingencies that are applicable to the area in study and are expected to produce more severe System impacts rather than every single potential contingency to set the limits conservatively while minimizing the time it takes to complete the solution, which is reflected in the phrase "applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES". In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, the SOL methodology could describe which TOP or RC has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance. Additionally, Requirement R4 Part 4.3 addresses when there is an impact to other Reliability Coordinator Areas.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL methodology. For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the RC Area (including other RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation".

Requirement R5

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing

Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

5.1. Specify the following single Contingency:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in the evaluation of post-Contingency state in OPAs and RTAs (thermal and voltage). The SOL methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. These Contingencies, if any, must be specified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Part 5.3 compliments the proposed Requirement R8 in FAC-014-3 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R5 establishes the contingency events for use in determining stability limits, in performing Operational Planning Analysis (OPAs), and in performing Real-Time Assessments (RTAs). The standard requirement is not meant to imply that all TOPs within the RC footprint must use that identical list spanning the entire RC region but may use a reduced list that at least covers the area they are responsible for the most limiting Contingencies.

Requirement R6

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses, :

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady State flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its normal rating could be executed and completed within the specified time duration of those Emergency Ratings

6.1.2. Steady State flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met.

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 and subparts R2.1 and R2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed TOP-001-5 Requirement R25 and IRO-008-3 R7 to support reliable operations for pre- and post-Contingency operating states. TOP-001 Requirement R25 states, *"Each Transmission Operator shall use the applicable RC's SOL methodology when*

determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis." IRO-008-3 Requirement R7 states*, "Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."* The above noted requirements in TOP-001 and IRO-008 ensure that the performance framework identified in the SOL methodology is used to determine SOL exceedances consistently between the RC and its associated TOPs during Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis..*"*

FAC-011-4 Requirement R6, Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA no Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Steady state flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator may have insufficient time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow. However, as noted in the NERC SOL Whitepaper, pre-Contingency load shed may not be necessary or appropriate when assessment identifies that the impact is localized.

Requirement 6 applies only to those contingencies specified by the Reliability Coordinator for monitoring in the Transmission Operators RTA and OPA. If the Transmission Operators monitors additional contingencies beyond the subset required by the Reliability Coordinator, they are not required to meet the performance metrics in Requirement 6. As an example, if a TOP chooses to monitor loss of an entire substation as a contingency within their contingency analysis this section does not require that system performance following that event must meet these performance requirements. If the loss of a substation was not a defined contingency in the RC's SOL methodology, and no other defined contingency could cause loss of the entire substation, then the TOP could define what performance criteria, if any, to apply to this contingency. Said simply, R6 specifically applies only to the events and conditions described in R5.

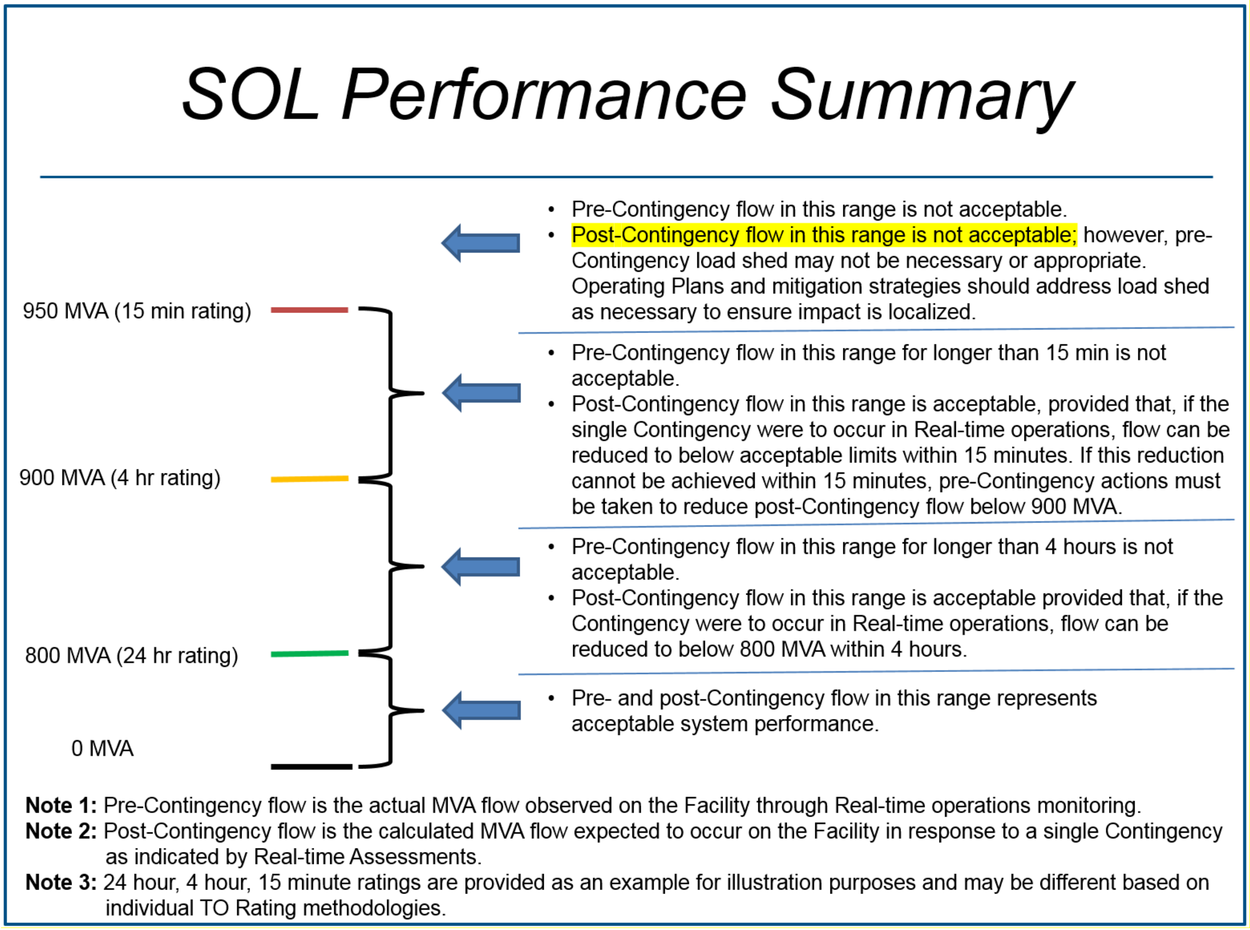

Figure 1 of the NERC SOL Whitepaper

The footnote referenced in Part 6.1.4 and 6.2.3 states, "*Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.*" This helps to provide clarity that there are multiple methods to assessing if System performance demonstrates that Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA and Real time monitoring. Other entities may utilize tools that run at the time of the study to assess for acceptable performance or determine stability limits at the time of the OPA or RTA. Others may yet utilize other offline analysis techniques.

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5, Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation that adversely impact the reliability of the Bulk Electric System.

Part 6.4 maintains the concept identified in FAC-011-3 R2.3.2 and intent of FERC Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Requirement Part 6.4 clarifies that load shedding as a remedy in the operating plan should only be allowed after other options are exercised without regard for financial impact. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost, when the generation has a significant impact on the SOL exceedance.
- Curtailment and adjustment of Interchange regardless of economic cost, when the Curtailment or adjustment of Interchange has a significant impact on the SOL exceedance.
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Transmission re-configuration that does place more load at risk or create other unacceptable system performance issues is not required to be used prior to planned manual load shedding. As an example the reconfiguration of a looped network into a series of radial connections to avoid planned post contingency load shedding could be a re-configuration that puts more load at risk. In those circumstances the TOP and RC must select that option that best fits their operating conditions and the requirement is not intended to prescribe one approach over the other.

Requirement R7

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include:

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances;

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation;

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and

7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.

Rationale R7

The changes in proposed FAC-011-4 help to provide clarity by requiring a performance framework for determining SOL exceedances in the RC's SOL methodology. This provides better uniformity in determining what is and isn't an SOL exceedance. This clarity may increase the instances of what is determined to be an SOL exceedance and thus increase the instances of communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirement R5 and R6) which states, "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.*"

Concerns were raised as to the effect on Real-time System Operators being required to communicate every SOL exceedance, especially those which were considered short duration SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

Part 7.1 requires that the risk based approach require that "IROL exceedances, SOL exceedances of stability limits, post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation and pre-contingency SOL exceedances of Facility Ratings and pre-contingency Low System Voltage Limits will always be communicated". While typically less frequent, these subset of SOL exceedances were determined to be of a higher risk and must always be communicated between TOP's and RC's. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Part 7.2 requires that the risk based approach require that "Post-contingency SOL exceedances of Facility Ratings and System Voltage limits and pre-contingency Normal High System Voltage Limits must be communicated, if not resolved, within a timeframe identified by the RC which cannot exceed 30 minutes". While typically more frequent, these subset of SOL exceedances were determined to be of a lower risk allow the RC to identify a timeframe which cannot exceed 30 minutes whereby if the SOL exceedance is mitigated (no longer an SOL exceedance) within the identified timeframe (e.g. 15min, 30 min, etc.), the SOL exceedance would not be required to be communicated to the TOP or RC. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Nothing prohibits an RC from requiring all or an additional subset of SOL exceedances than what is identified in Part 7.1 from being communicated. Nothing prohibits a Real-time System Operator from communicating beyond what is required or in line with other good utility practice (e.g. troubleshooting or communicating). These provisions are meant to ensure that a risk based approach can be applied to prevent low risk or after the fact communications from distracting System Operators from other higher priority tasks.

This proposed requirement is coordinated with proposed changes to TOP-001-5 Requirement R15 which states "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology.***" and with proposed IRO-008-3 Requirements R5 and R6 which state, **"***Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology***.*"* and **"***Each Reliability Coordinator shall notify***, in accordance with SOL methodology***, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.***"**, respectfully.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL methodology:

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.

Rationale R8

The two IROL related requirements in FAC-011-3 were preserved under Requirement R8. Part 8.2 utilizes terminology consistent with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards by replacing "violating" with "exceeding". It also inserts "exceeding" before the IROL to better harmonize with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards.

Requirement R9

R9. Each Reliability Coordinator shall provide its SOL methodology to:

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Rationale R9

Requirement R9 preserves the reliability objective of providing the SOL methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC's SOL methodology.

In Requirement R9 Sub-part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Sub-part 9.2.2 also uses "responsible for planning" instead of "models any portion of" to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Sub-part 9.2.4 differs from Requirement R9 Sub-parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

Technical Rationale for Reliability Standard FAC-014-3

April 2020

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP “shall establish SOLs (as directed by its Reliability Coordinator)” because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been “directed to by their RC.” This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC’s SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC’s documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC’s SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC. It’s important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the

Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, R5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required by R4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Requirement R5 Parts 5.3 through 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models. Analysis of these models determines System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:

Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans or the use of ambient temperature assumptions in seasonal planning models versus those assumptions used in operational analyses and monitoring in real time may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases are appropriately included in future planning models. These provisions should be included in the documented technical rationale is provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and

TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall communicate, annually, any instability, Cascading or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Owner and Generation Owner. This communication shall include those Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified.

Rationale R8

This requirement was drafted to ensure the appropriate details regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. This is necessary to ensure owners receive this input for use in their identification of Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT’s proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Additionally, this requirement aligns with TPL-001-4 Requirement R6 pertaining to the Planning Assessment which states, “Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.”

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standards Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners.

Technical Rationale for Reliability Standard IRO-008-3

June 2020

IRO-008-3 – Reliability Coordinator Operational Analyses and Real-Time Assessments

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:

Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

Rationale for R2 and R3:

Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

Rationale for R5 and R6:

In Requirements R5 and R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications. The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other

real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard.

Rationale for R7: Requirement R7 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

Technical Rationale for Reliability Standard TOP-001-6

April 2020

TOP-001-6 – Transmission Operations

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.

Rationale for Requirement R3:
The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:
New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and

studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:
The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

FAC-011-4 R6 clarifies when an SOL exceedance is occurring and as such likely increases the number of SOL exceedances for some TOPs. This increased number of SOL exceedances could create an administrative burden on Real-Time System Operators for entities that rely on operator logs as the primary form of evidence for compliance. This would be an unintended consequence of interaction between the new FAC-011-4 R6 and TOP-001-4 Requirement 14, which states, "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." This is because TOP-001-4 Requirement 14 treats all SOL exceedances equally and does not differentiate among them based on duration or risk to the BES.

Concerns were raised by drafting team members and observers as to the effect on Real-Time System Operators being required to log initiation of the Operating Plan for every SOL exceedance per TOP-001-4 R14, especially those which were considered short duration, low risk SOL exceedances that were actually successfully mitigated within a short-term time frame. This could distract Real-Time System Operators to focus on compliance documentation during times when they should be fully committed to implementing the Operating Plan and mitigating the SOL exceedance.

The revised TOP-001-6 M14 addresses this concern by identifying examples of "other evidence" that can be utilized to support compliance which require less human intervention for capturing. Examples allowing TOPs to use other types of evidence such as system logs/records showing the SOL exceedance successfully mitigated in conjunction with Operating Plans is important because it clarifies that validation of successful SOL mitigation is the primary interest and focus of evidence. Successful SOL mitigation coupled with Operating Plans that have been prepared for utilization in the event of an SOL exceedance can demonstrate that the TOP initiated and implemented its Operating Plan. For example, providing outputs of State Estimator and/or Real-Time Contingency Analysis (with start time and end time of SOL exceedances) in conjunction with Operating Plans that outline roles and responsibilities between TOP and its RC in eliminating SOL exceedances, would document resolution of the SOL exceedance as well as the Operating Plan in use for the resolution. These should be sufficient evidence for Requirement R14 while reducing or eliminating the administrative burden on Real-Time System Operators to manually generate compliance evidence via logging or recording actions.

These Operating Plans may be strengthened with clarifying information such as automatically switched or scheduled switching operating strategies/processes that describe how automatic control actions correct SOL exceedances, which can prevent unnecessary collection of evidence. Use of operating policies as a part of Operating Plan may include specific control actions (such as taking a transmission line out of service or disconnecting a generator for a low risk high voltage SOL exceedance) on post-contingent basis, and may be utilized if it was included into operating protocols and confirmed in real-time. Other records, such as binding constraint logs, could document the actions taken to alleviate certain thermal SOL exceedances through the role of redispatch algorithms that generate revised dispatch setpoints for generators to alleviate the constraint.

Finally, further evidence may include some of the operating protocols shared between a TOP and RC as part of the Operating Plan; they may support instances where the TOP and RC agree to each take certain predetermined actions and or share information. For example, if an RC had to initiate manual redispatch with a Generator Operator when a TOP initiated binding constraint was insufficient (e.g. not fast enough), the TOP may utilize RC-provided logs as evidence of compliance if the RC and TOP have agreed to share such information. Additionally, use of these joint operating protocols as evidence recognizes situations

and operating conditions when the RC initiates and implements an Operating Plan on behalf of TOP, per these joint operating protocols. In these situations, pre-specified actions taken by the TOP and RC and agreed upon in their joint operating protocols could allow the RC's binding constraint logs to be used by the TOP as evidence of compliance.

Rationale for Requirement R15:
Clarity of what is determined to be an SOL exceedance in new revision FAC-011-4 may increase, in some instances, the number of SOL exceedances and thus the communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirement R5 and R6) which states, "Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded."

Concerns were raised as to the effect on Real-time System Operators being required to communicate every SOL exceedance, especially those which were considered short duration, low risk, SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements of TOP-001-5 R15 with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard.

Rationale for Requirements R16 and R17:
In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication

paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R25: Requirement R25 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC’s SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:

The approved definition of SOL as defined in the NERC Glossary of Terms is:

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
- *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
- *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
- *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

The concept of SOL determination is not complete without looking at the associated NERC FAC standards approved FAC-008-3, proposed FAC-011-4, and proposed FAC-014-3 and related TOP and IRO standards (proposed TOP-001-6 and IRO-008-3):

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. The standard requires both Generation Owners

and Transmission Owners to have a documented Facility Ratings methodology and to establish Facility Ratings consistent with that methodology that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed are required to include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal Rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Emergency Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of proposed FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:
    a. Requirement R2 requires that the Reliability Coordinator’s SOL methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.
    b. Requirement R3 requires that the Reliability Coordinator’s SOL methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.
    c. Requirement R4 requires that the Reliability Coordinator’s SOL methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements.
3. Proposed FAC-011-4 requirement R6 contains the minimum framework for SOL exceedance determination to be used in the TOP and IRO standards. Specifically, requirement R6 requires the Reliability Coordinator’s SOL methodology to include, at a minimum, the following Bulk Electric System performance framework:
    a. Part 6.1: System performance for no Contingencies demonstrates the following:

        Part 6.1.1: Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

        Part 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

Part 6.1.3. Predetermined stability limits are not exceeded.

Part 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

i. Part 6.1.3:

b. Part 6.2: System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

   i. Part 6.2.1: Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

   ii. Part 6.2.2: Steady state post-Contingency voltages are within emergency System Voltage Limits.

   iii. Part 6.2.3: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

   iv. Part 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1]

c. Part 6.3: System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

d. Part 6.4: In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

4. Proposed FAC-014-3, Requirement R2 requires that Transmission Operators to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

5. Proposed TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 require Transmission Operators and Reliability Coordinators, respectively, to use the Reliability Coordinator's SOL methodology when performing Real-time Assessments, Real-time Monitoring, and Operational Planning Analyses to determine SOL exceedances. The SOL exceedance framework is included in the SOL methodology via the proposed FAC-011-4 requirement R6 (above).

6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all Facilities that can

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into operations studies.

Some have interpreted the language in previous versions of FAC-011 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in FAC-011, with the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in FAC-011 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within FAC-011, which is both:

1. To know the Facility Ratings, voltage limits, transient Stability criteria, and voltage Stability criteria, and
2. To ensure that they are all observed in assessments of both the pre- and post-Contingency state when performing Operational Planning Analyses (OPA), Real-time Assessments (RTA), and Real-time monitoring.

It is important to understand the intent behind the language "the pre- and post-contingency state." The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. In Real-time operations, any of these types of limits can be the most restrictive limit at any point in time in the pre- or post-Contingency state. For example, if an area or Facility of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of thermal Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, a primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. How an entity accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **System Voltage Limits:**
   In the pre-Contingency and post-Contingency state, operate within normal System Voltage Limits and emergency System Voltage Limits, as applicable, within their associated time parameters.
3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC’s SOL methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage response, unit stability, and System damping. Part 4.2 requires stability limits to be established to meet these prescribed stability performance criteria. For example, a study might

indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

Transient Stability Limits:
Transmission Operators establish transient stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or loading level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

Voltage Stability Limits:
Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:
The combination of requirements contained within the proposed FAC and the proposed and approved TOP and IRO standards, as well as the use of defined terms contained within those standards such as OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe a performance framework for the pre- and post-Contingency state (proposed FAC-011-4 requirement R6) for SOL exceedance determinations.
2. TOP-001-3, Requirement R13 requires that each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. TOP-001-6, Requirement R25 requires that each Transmission Operator shall use the applicable Reliability Coordinator’s SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.
4. TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
5. TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

6. IRO-008-3, Requirement R7 requires that each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

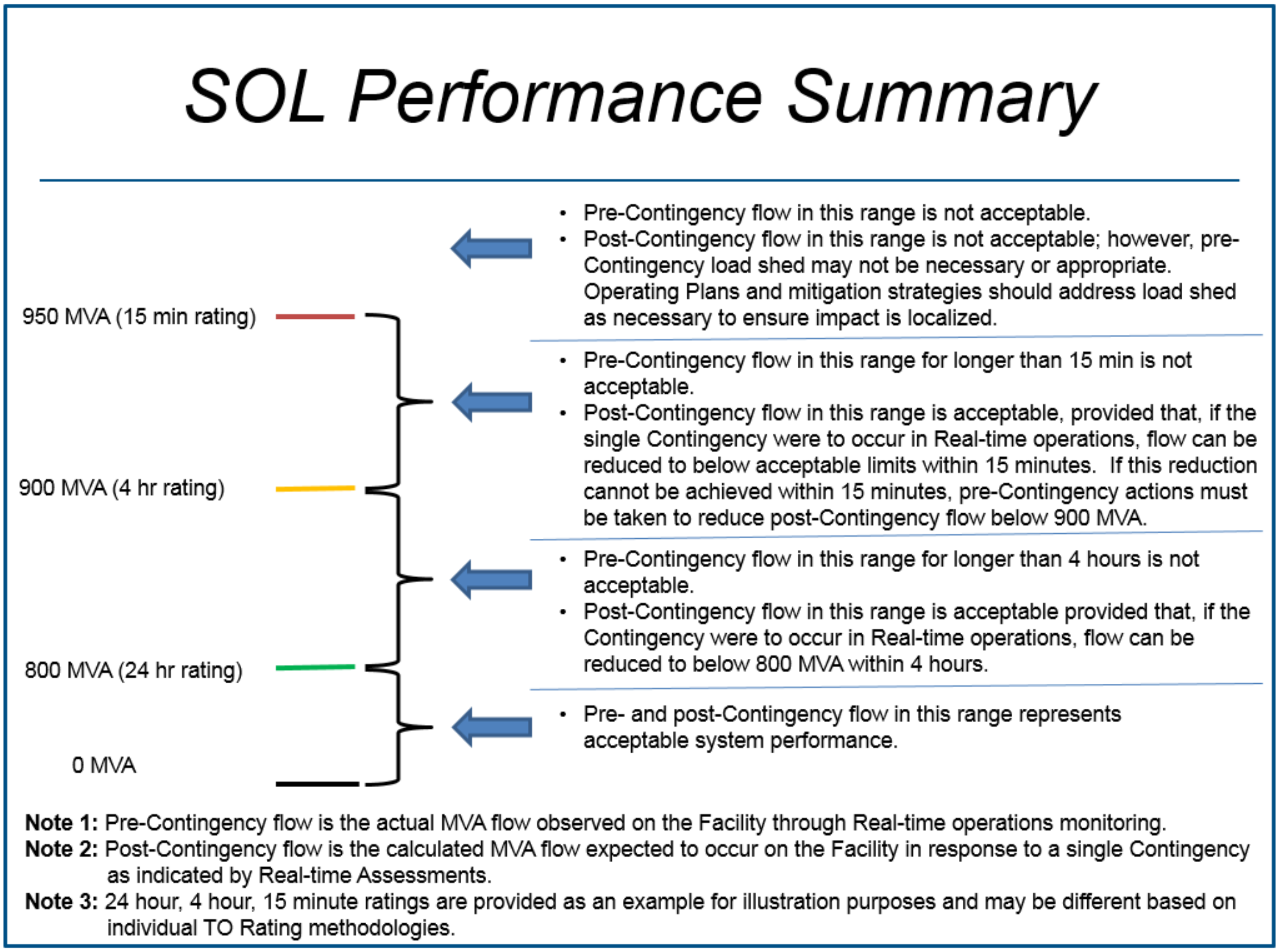

Figure 1. Facility Rating System Operating Limit Performance Summary

The following example scenarios describe appropriate operator action with respect to Figure 1:

1. **<u>Example 1 Scenario</u>** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) It is important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable

operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating if actions were available to be taken.

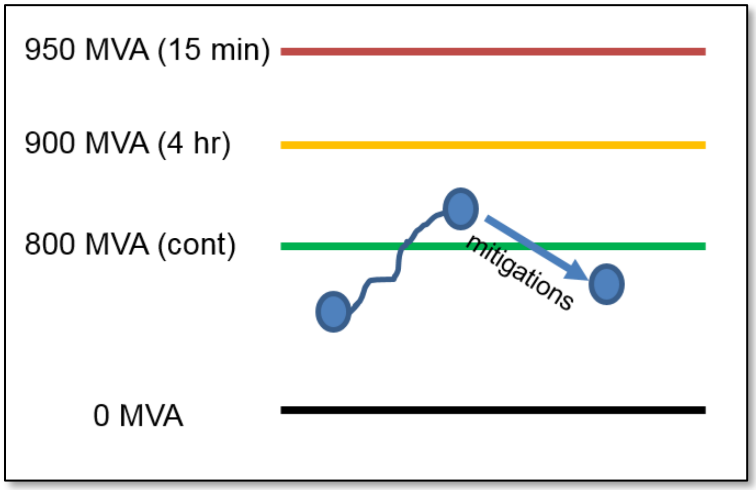

Figure 2. Example 1 Scenario – Pre-Contingency State

2. **Example 2 Scenario** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 stable.

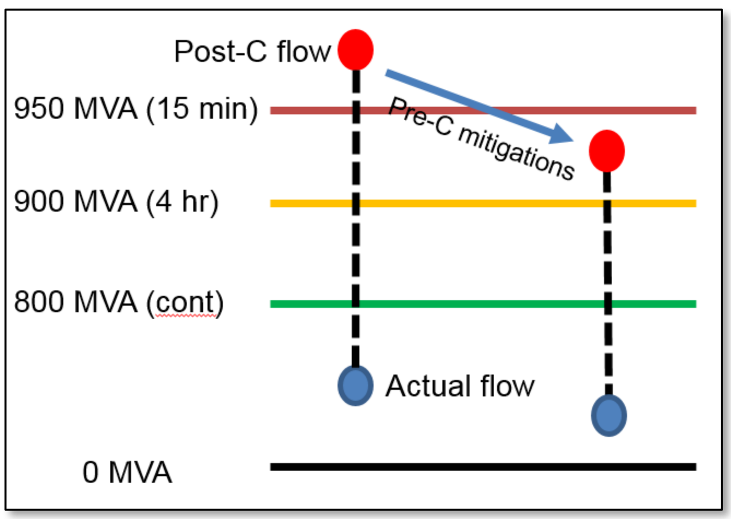

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **Example 3 Scenario** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending on how the line is rated based on the Transmission Owner's Facility Ratings methodology. If this

information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

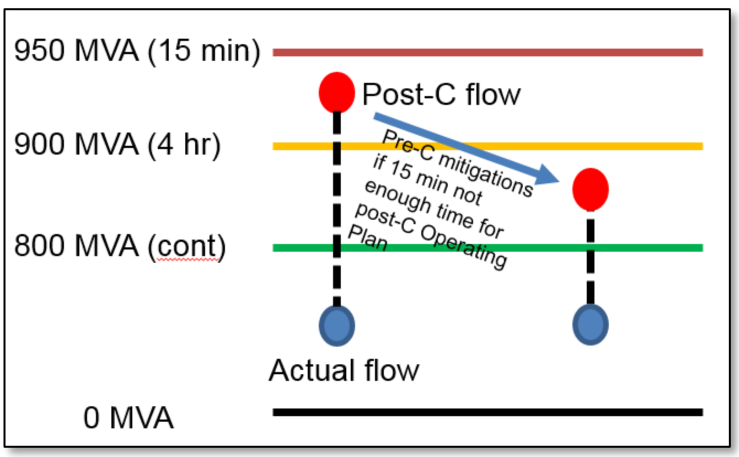

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **<u>Example 4 Scenario</u>** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would

immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

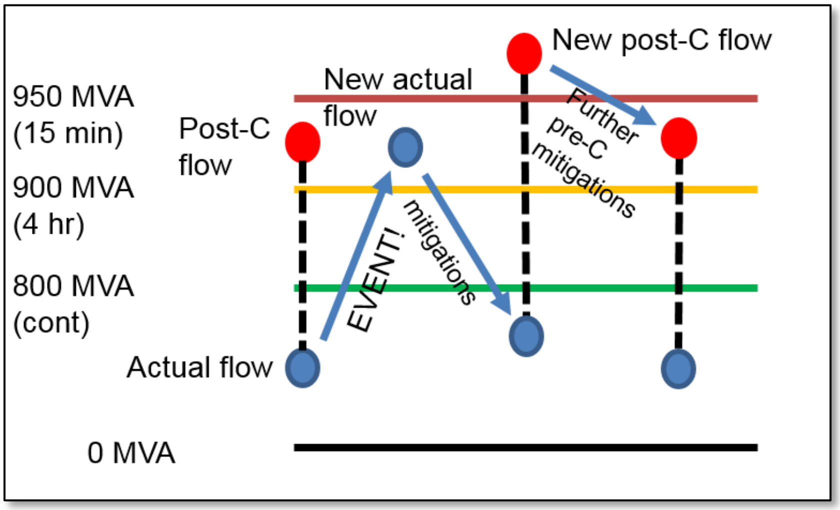

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

Steady State Voltage Limit Exceedance

SOL performance for System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency System Voltage Limits are required to be established by the TOP in accordance with the RC's SOL methodology. FAC-011-4 Requirement R3 requires that the RC's SOL methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings methodology per approved FAC-008-3.

Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL methodology. Real-time Assessments should recognize the impact of automatically controlled reactive devices and whether or not those devices are sufficient without manual operator action for maintaining voltages within System Voltage Limits pre- or post-Contingency.

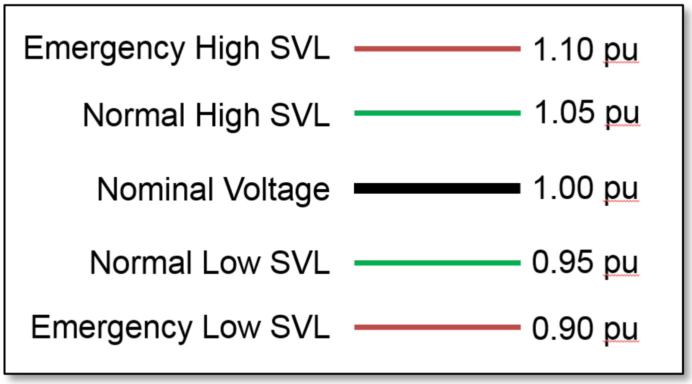

Figure 6. Example of a System Voltage Limit Set

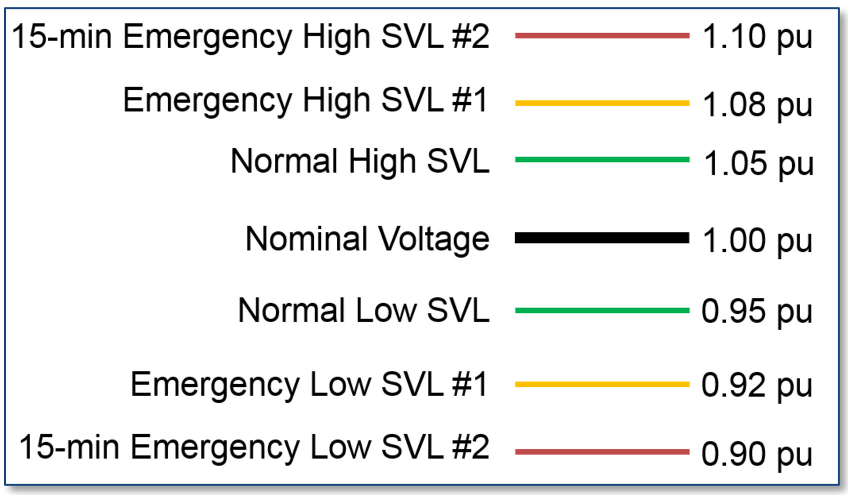

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area's voltage Stability performance exceeds an SOL that qualifies as an IROL. In this example, the SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

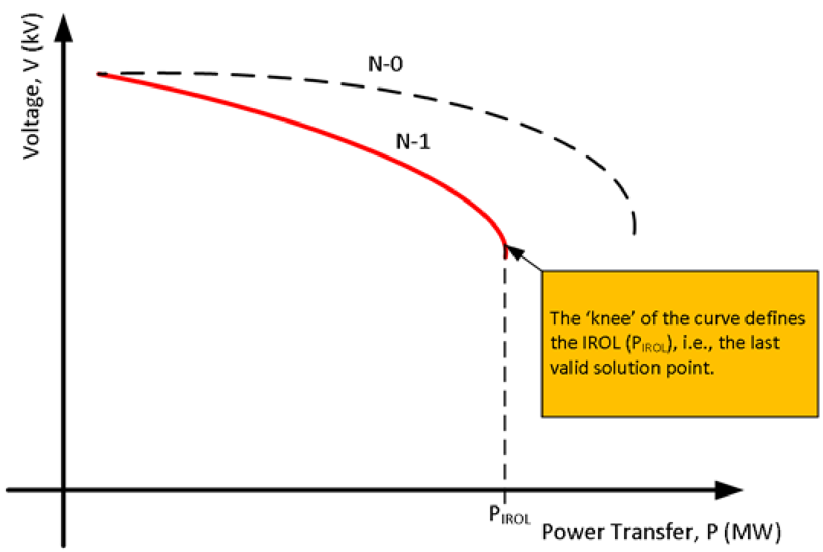

Figure 8. Voltage Stability System Operating Limit Performance Summary

SOL Exceedance and Operating Plans:

SOL exceedances occur when the performance framework described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedances are determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedances are determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedances are identified through the evaluation of the pre-Contingency state and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific

Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure acceptable BES performance is maintained, preventing SOL exceedances from escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Use available effective actions and emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**
Emergency (15 min)	**All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.**

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time

Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts, generation output levels, Interchange, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Facility Ratings, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:

The approved definition of SOL as defined in the NERC Glossary of Terms is:

> *The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
> - *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
> - *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
> - *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The concept of SOL determination is not complete without looking at the associated NERC FAC standards approved FAC-008-3, proposed FAC-011-4, and proposed FAC-014-3 and related TOP and IRO standards (proposed TOP-001-6 and IRO-008-3):

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. The standard requires both Generation Owners

and Transmission Owners to have a documented Facility Ratings ~~M~~methodology and to establish Facility Ratings consistent with that methodology that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed are required to include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal Rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Emergency Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of proposed FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:
   a. Requirement R2 requires that the Reliability Coordinator's SOL ~~M~~methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.
   b. Requirement R3 requires that the Reliability Coordinator's SOL ~~M~~methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.
   c. Requirement R4 requires that the Reliability Coordinator's SOL ~~M~~methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements. ~~Part 4.5 requires that the RC's SOL Methodology describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.~~

3. Proposed FAC-011-4 requirement R6 contains the minimum framework for SOL exceedance determination to be used in the TOP and IRO standards.~~performance criteria for BES operations.~~ Specifically, requirement R6 requires the Reliability Coordinator's SOL ~~M~~methodology to include, at a minimum, the following Bulk Electric System performance ~~criteria~~framework:
   a. Part 6.1: System performance for no Contingencies demonstrates the following~~The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following~~:
      Part 6.1.1: Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings~~Flow through Facilities are within Normal~~

~~Ratings; however, Emergency Ratings may be used only when System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings~~.

Part 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

Part 6.1.3. Predetermined stability limits are not exceeded.

Part 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

~~i.~~

~~ii. Part 6.2.1: Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used only when System adjustments to return the voltage within its normal System Voltage Limits can be executed and completed within the specified time duration of those emergency System Voltage Limits.~~

~~iii.~~i. Part 6.1.3: ~~Instability, Cascading, or uncontrolled separation do not occur.~~

b. Part 6.2: System performance for the single Contingencies listed in Part 5.1 demonstrates the following~~The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following~~:

i. Part 6.2.1: Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating~~Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments can be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating~~.

ii. Part 6.2.2: Steady state post-Contingency voltages are within emergency System Voltage Limits~~Voltages are within emergency System Voltage Limits~~.

iii. Part 6.2.3: The stability performance criteria defined in the Reliability Coordinator's SOL ~~M~~methodology are met[1]~~[1]~~~~Instability, Cascading, or uncontrolled separation do not occur~~.

~~iii.~~iv. Part 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1]~~[1]~~

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

c. Part 6.3: System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur~~The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur~~.

d. Part 6.4: In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made~~The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur~~.

~~e. Part 6.5: In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.~~

4. Proposed FAC-014-3, Requirement R2 requires that Transmission Operators to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

5. Proposed ~~FAC-014-3~~TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7~~7~~ require~~s~~ Transmission Operators and Reliability Coordinators, respectively, to use the ~~Bulk Electric System performance criteria specified in the~~ Reliability Coordinator's SOL ~~M~~methodology when performing Real-time Assessments, Real-time Monitoring, and Operational Planning Analyses ~~OPAs, RTAs, and Real-time monitoring~~ to determine SOL exceedances. The~~se~~ SOL exceedance ~~performance~~ framework~~criteria~~ is~~are reflected~~ included in the SOL methodology via ~~in~~the proposed FAC-011-4 requirement R6 (above).

6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all Facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into operations studies.

Some have interpreted the language in previous versions of FAC-011 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in FAC-011, with the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in FAC-011 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within FAC-011, which is both:

1. To know the Facility Ratings, voltage limits, transient Stability ~~limits~~criteria, and voltage Stability criteria~~limits~~, and
2. To ensure that they are all observed in assessments of both the pre- and post-Contingency state when performing Operational Planning Analyses (OPA), Real-time Assessments (RTA), and Real-time monitoring.

It is important to understand the intent behind the language “the pre- and post-contingency state.” The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability ~~limits~~ criteria for the pre- and post-Contingency state. In Real-time operations, any of these types of limits can be the most restrictive limit at any point in time in the pre- or post-Contingency state. For example, if an area or Facility of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of thermal Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, a primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System

Voltage Limits, and transient and voltage stability criteria ~~limits~~ for the pre- and post-Contingency state. How an entity accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.

2. **System Voltage Limits:**
   In the pre-Contingency and post-Contingency state~~state~~, operate within normal System Voltage Limits and emergency System Voltage Limits, as applicable, within their associated time parameters~~. In the post-Contingency state, operate within applicable emergency System Voltage Limits~~.

3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC's SOL ~~M~~methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage response, unit stability, and System damping. Part 4.2 requires stability limits to be established to meet th~~ei~~se prescribed stability performance criteria. For example, a study might indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

   Transient Stability Limits:
   Transmission Operators establish transient stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are

typically defined as the maximum power transfer or loading level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

Voltage Stability Limits:
Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the proposed FAC and the proposed and approved TOP and IRO standards, as well as the use of defined terms contained within those standards such as OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe ~~acceptable system~~a -performance framework~~criteria~~ for the pre- and post-Contingency state (proposed FAC-011-4 requirement R6) for SOL exceedance determinations.
2. TOP-001-3, Requirement R13 requires that each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
~~2.~~3. TOP-001-6, Requirement R25 requires that each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.
~~3.~~4. TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
5. TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.
~~4.~~6. IRO-008-3, Requirement R7 requires that each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

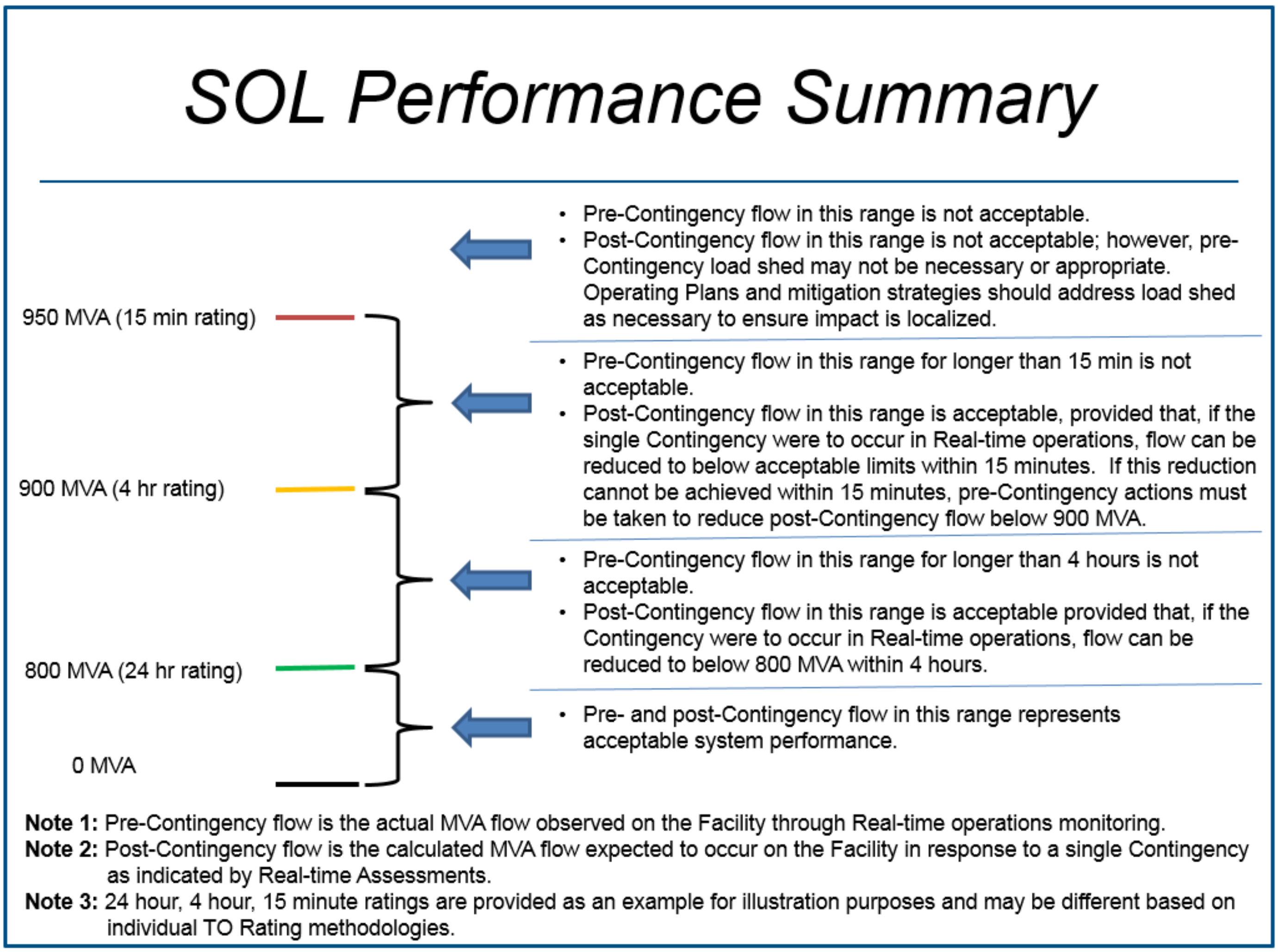

Figure 1. Facility Rating System Operating Limit Performance Summary

The following example scenarios describe appropriate operator action with respect to Figure 1:

1. **Example 1 Scenario** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) It~~s~~ is~~t~~ important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating if actions were available to be taken.

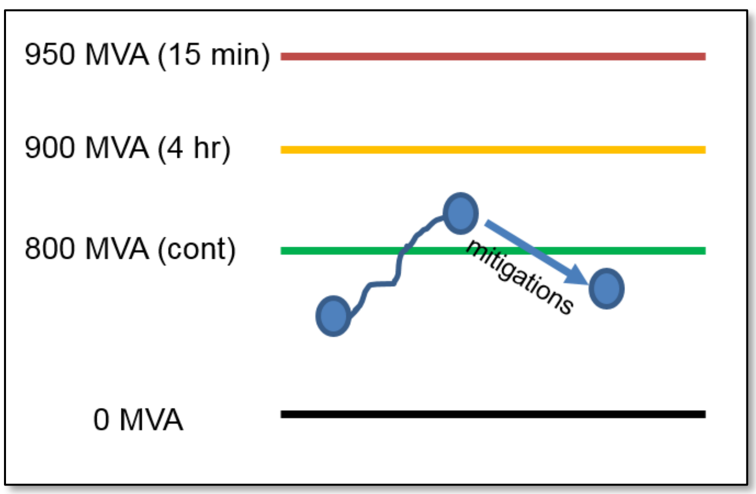

Figure 2. Example 1 Scenario – Pre-Contingency State

2. **Example 2 Scenario** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 stable.

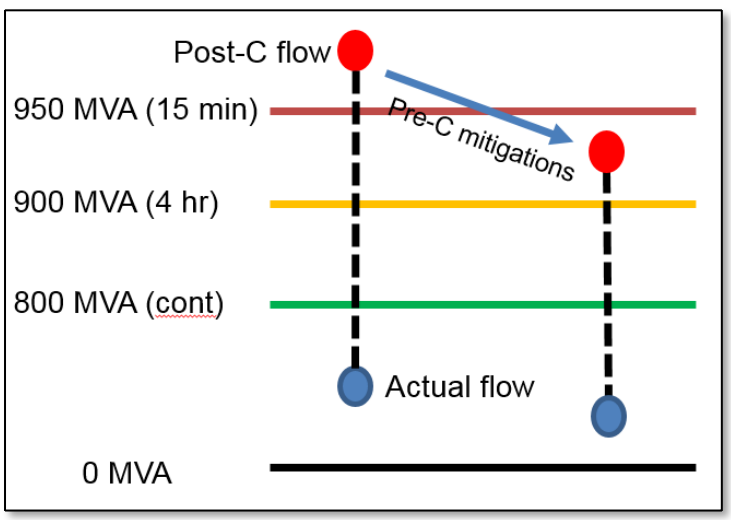

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **Example 3 Scenario** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending on how the line is rated based on the Transmission Owner's Facility Ratings ~~M~~methodology. If this

information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

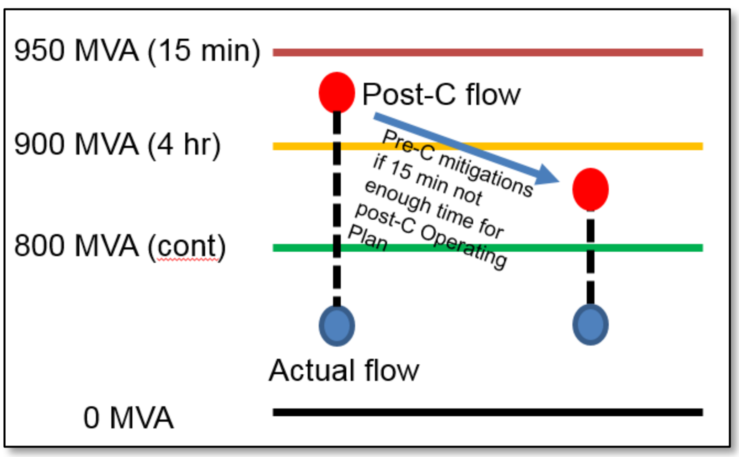

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **Example 4 Scenario** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would

immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

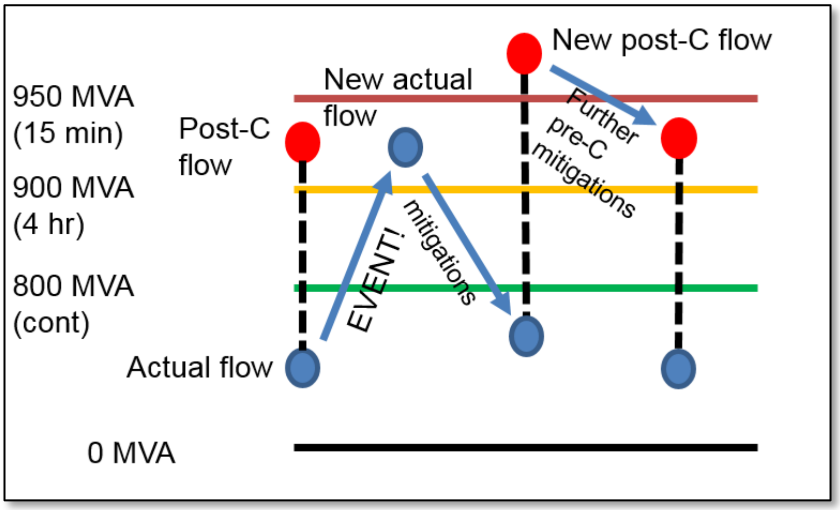

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

<u>Steady State Voltage Limit Exceedance</u>

SOL performance for System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency System Voltage Limits are required to be established by the TOP in accordance with the RC's SOL ~~M~~methodology. FAC-011-4 Requirement R3 requires that the RC's SOL ~~M~~methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings ~~M~~methodology per approved FAC-008-3.

Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL ~~M~~methodology. Real-time Assessments should recognize the impact of automatically controlled ~~-~~reactive devices and whether or not those devices are sufficient without manual operator action for maintaining voltages within System Voltage Limits pre- or post-Contingency.

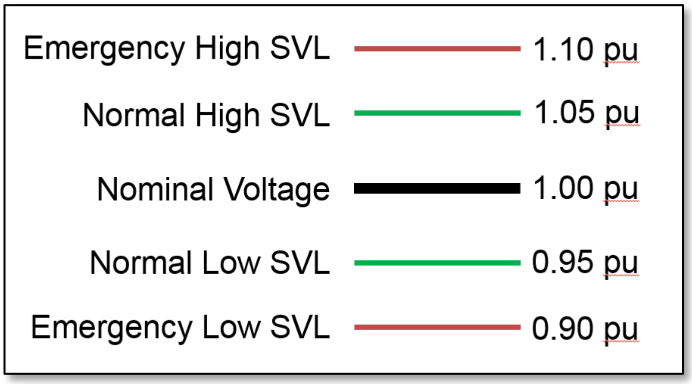

Figure 6. Example of a System Voltage Limit Set

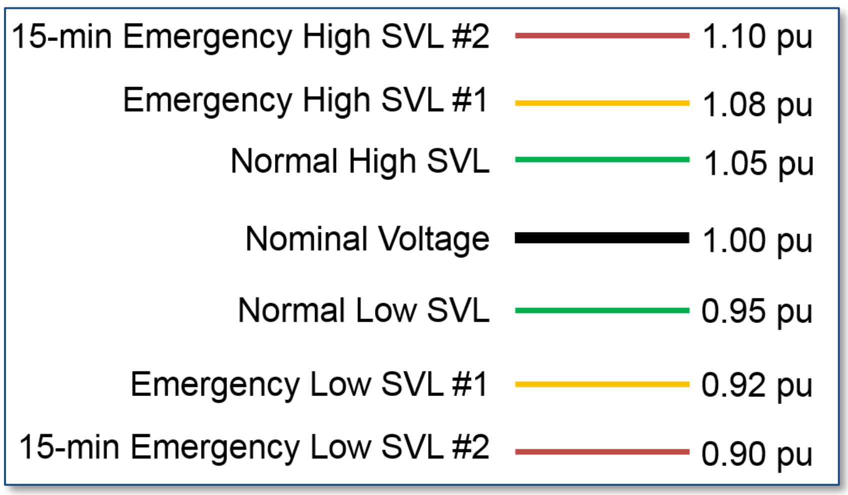

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area's voltage Stability performance ~~based SOL~~ exceeds an SOL that qualifies as an IROL. In this example, the SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

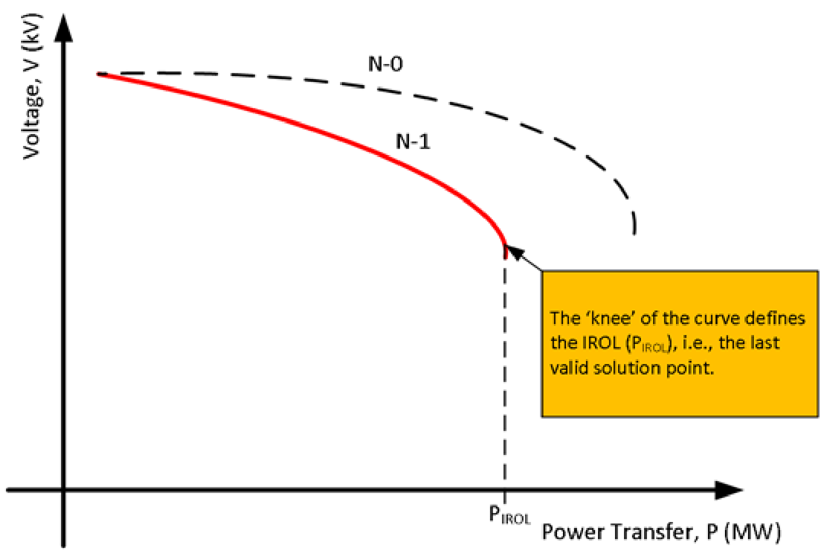

Figure 8. Voltage Stability System Operating Limit Performance Summary

SOL Exceedance and Operating Plans:

SOL exceedances occur~~s~~ when the performance ~~criteria as~~framework described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedances are~~is~~ determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedances are~~is~~ determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedances are~~is~~ identified through the evaluation of the ~~actual state (or~~ pre-Contingency state~~)~~ and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are~~is~~ identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific

Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure acceptable BES performance is maintained ~~as per proposed FAC-011-4, Requirement R6~~, preventing SOL exceedances from escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Use available effective actions and emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.**
Emergency (15 min)	**All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.**	**Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.**

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time

Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts, generation output levels, Interchange, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Facility Ratings, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

DRAFT Reliability Standard Audit Worksheet[1]

FAC-011-4 - System Operating Limits Methodology for the Operations Horizon

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1						X						
R2						X						
R3						X						
R4						X						
R5						X						
R6						X						
R7						X						
R8						X						
R9						X						

Legend:

Text with blue background:	Fixed text – do not edit

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			
R9			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has a methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R2.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R2
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's methodology for establishing SOLs (i.e., SOL methodology) includes the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.
	Verify the method for Transmission Operators to determine the applicable owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Note to Auditor:

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

3.1. Require that BES buses/stations have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL methodology includes the method for Transmission Operators to determine the System Voltage Limits to be used in operations.
	Verify the method for Transmission Operators to determine the System Voltage Limits to be used in operations:
	(3.1) Requires that BES buses/stations have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit
	(3.2) Requires that System Voltage Limits respect the Facility voltage Ratings
	(3.3) Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs
	(3.4) Identifies the lowest allowable System Voltage Limit
	(3.5) Defines the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Cordinator Areas.

4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s); including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R4

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL methodology includes the method for determining the stability limits to be used in operations.
	Verify the method for determining the stability limits to be used in operations:
	(4.1) Specifies stability performance criteria, including any margins applied, and includes at a minimum:
	(4.1.1) steady-state voltage stability;
	(4.1.2) transient voltage response;
	(4.1.3) angular stability; and
	(4.1.4) System damping.
	(4.2) Requires that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.
	(4.3) Describes how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Cordinator Areas.
	(4.4) Describes how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;
	(4.5) Describes the level of detail that is required for the study model(s); including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.
	(4.6) Describes the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.
	(4.7) States that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

5.1. Specify the following single Contingency events:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7 to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the SOL methodology includes identifying the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs).
	(5.1) Verify the SOL methodology for each set includes specification of the following single Contingency events:
	(5.1.1) Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; or • single pole block in a monopolar or bipolar high voltage direct current system.
	(5.2) Verify the SOL methodology for each set specifies additional single or multiple Contingency events or types of Contingency events, if any.
	(5.3) Verify the SOL methodology for each set describes the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7 to use in determining stability limits.
Note to Auditor:	

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[3]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.[3]

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[3]

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.

[3] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R6

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL methodology includes the following performance framework to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:
	(6.1) System performance for no Contingencies, and demonstration of items 6.1.1., 6.1.2., 6.1.3., and 6.1.4.
	(6.2) System performance for the single Contingencies listed in Part 5.1, and demonstration of items 6.2.1., 6.2.2., 6.2.3., and 6.2.4..
	(6.3) System performance for applicable Contingencies identified in Part 5.2, and demonstration that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.
	(6.4) In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.
Note to Auditor:	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communications must occur. The approach shall include:

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances;

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation;

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits, and

7.2.2. Pre-contingency SOL exceedances of normal high System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity’s Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R7

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL methodology includes the risk based approach for Transmission Operators to communicate SOL exceedances identified as part of Real-time monitoring and Real-time Assessments to its Reliability Coordinator(s).
	Verify the entity's SOL methodology includes the risk based approach for Reliability Coordinators to communicate SOL exceedances identified as part of Real-time monitoring and Real-time Assessments to its affected Transmission Operator(s).
Note to Auditor: The approach for R7.1 must be communicated and thus must have a timeframe identified that communications must occur. The approach for R7.2, for SOL exceedances identified as part of 7.2.1 and 7.2.2. that have not been resolved within 30 minutes, must have a timeframe identified that communications must occur.	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each Reliability Coordinator shall include in its SOL methodology:

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R8
This section to be completed by the Compliance Enforcement Authority

	Verify the entity's SOL methodology includes a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

	Verify the entity's SOL methodology includes criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.
Note to Auditor:	

Auditor Notes:

R9 Supporting Evidence and Documentation

R9. Each Reliability Coordinator shall provide its SOL methodology to:

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

Registered Entity Response (Required):
Question: Has the entity made any changes to its SOL methodology during the audit period that modify the effective date of the SOL methodology? ☐ Yes ☐ No
If Yes, provide a list of changes including the date the change became effective. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Question: Has the entity received a request for its SOL methodology from a Reliability Coordinator that indicated it has a reliability-related need for the SOL methodology? ☐ Yes ☐ No
If Yes, provide a list of requests received. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Methodology for establishing SOLs (i.e., SOL methodology) within the entity's Reliability Coordinator Area.
Evidence the SOL methodology and any changes to the SOL methodology were provided to each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requests and indicates

it has a reliability-related need.
Evidence the SOL methodology and any changes to the SOL methodology were provided to each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area.
Evidence the SOL methodology and any changes to the SOL methodology were provided to each Transmission Operator within the entity's Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-011-4, R9

This section to be completed by the Compliance Enforcement Authority

	(9.1) Verify that the entity provided its SOL methodology to each Reliability Coordinator that requested and indicated it had a reliability-related need within 30 days of a request.
	(9.2.1) Verify entity provided, prior to the effective date of the SOL methodology, its SOL methodology to each adjacent Reliability Coordinator within the same Interconnection.
	(9.2.2) Verify entity provided, prior to the effective date of the SOL methodology, its SOL methodology to each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area.
	(9.2.3) Verify entity provided, prior to the effective date of the SOL methodology, its SOL methodology to each Transmission Operator within its Reliability Coordinator Area.
	(9.2.4) Verify entity provided, prior to the effective date of the SOL methodology, its SOL methodology to each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.
Note to Auditor: 30 days will be interpreted as 30 "calendar" days since "business" days was not identified as a qualifier.	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.
The full text of FAC-011-4-N may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]
Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]
The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	XX/XX/XXXX	RSAW Working Group	New Document

Revision History for RSAW Template

Version	Date	Reviewers	Revision Description
0.9	11/6/2013	RSAW Working Group	Initial Draft
1.0	11/20/2013	CMFG	First Review
1.1	12/1/2014	RSAW TF, CMFG	Minor text changes
1.2	2/17/2014	Jerry Hedrick	Removed Internal Controls approach for additional consideration
1.3	4/9/2014	CIP-014-1 RSAW DT; RSAW TF	Changed the footnote on Evidence Requested to an Endnote. Moved example language from multiple areas to Developer's Guide.
3.0	1/20/2017		Deleted IA, LSE, PSE columns from Applicability; changed PA column to PA/PC. Updated page footer with new template version.
4.0	7/7/2020	NERC Compliance Assurance, RSAW Task Force	Updated for draft 3 on the project page

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

DRAFT Reliability Standard Audit Worksheet[1]

FAC-014-3 – Establish and Communicate System Operating Limits

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1						X						
R2										X		
R3										X		
R4						X						
R5						X						
R6					X						X	
R7					X						X	
R8					X						X	

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established IROLs in accordance with it SOL methodology.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i] :

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's System Operating Limit Methodology (SOL methodology).
Evidence IROLs for the entity's Reliability Coordinator Area have been established in accordance with entity's SOL methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has established IROLs for its Reliability Coordinator Area in accordance with its SOL methodology.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's Reliability Coordinator's System Operating Limit methodology (SOL methodology).
Evidence the entity established SOLs in accordance with its Reliability Coordinator's SOL methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R2
This section to be completed by the Compliance Enforcement Authority

	Verify the entity has established SOLs in accordance with its Reliability Coordinator's SOL methodology.
Note to Auditor:	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator's SOL methodology.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's Reliability Coordinator's System Operating Limit methodology (SOL methodology).
Evidence SOLs were provided to the entity's Reliability Coordinator.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the entity provided its SOLs to its Reliability Coordinator.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall establish stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Entity's System Operating Limit methodology (SOL methodology).
Evidence entity established stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with entity's SOL methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R4
This section to be completed by the Compliance Enforcement Authority

	Verify the entity established stability limits when the limit impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with entity's SOL methodology.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies);

5.2.5. A description of system conditions associated with the stability limit or IROL; and

5.2.6. The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 - 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity provided SOLs for Reliability Coordinator Area (including the subset of SOLs that are IROLs) to each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area at least once

every twelve calendar months.
Evidence the entity provided the information specified in Parts 5.2.1 – 5.2.6 for each established stability limit and each established IROL to each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area at least once every twelve calendar months.
Evidence the entity provided the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, to each impacted Transmission Operator within its Reliability Coordinator Area.
Evidence the entity provided the information identified in Requirement R5 Parts 5.2.2 - 5.2.6 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, to each impacted Transmission Operator within its Reliability Coordinator Area.
Evidence the entity provided requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule, to each requesting Transmission Operator within its Reliability Coordinator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R5

This section to be completed by the Compliance Enforcement Authority

	(5.1) Verify the entity provided SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) to each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area at least once every twelve calendar months.
	(5.2) Verify the entity provided the following information for each established stability limit and each established IROL to each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area at least once every twelve calendar months:
	(5.2.1) The value of the stability limit or IROL
	(5.2.2) Identification of the Facilities that are critical to the derivation of the stability limit or IROL;
	(5.2.3) The associated IROL T_v for any IROL;
	(5.2.4) The associated Contingency(ies);

	(5.2.5) A description of system conditions associated with the stability limit or IROL; and
	(5.2.6) The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).
	(5.3) Verify the entity provided the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, to each impacted Transmission Operator within its Reliability Coordinator Area.
	(5.4) Verify the entity provided the information identified in Requirement R5 Parts 5.2.2 - 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, to each impacted Transmission Operator within its Reliability Coordinator Area.
	(5.5) Verify the entity provided each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.
Note to Auditor: Some stability limits may be determined at the time of the assessment while others may be determined by a series of offline studies. For either instance, a single representative value or table of values may be communicated at the required time frame.	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

Registered Entity Response (Required):
Question: Does the entity use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are less limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology? ☐ Yes ☐ No
If Yes, evidence the entity provided a technical rationale to each of the required Transmission Planners, Transmission Operators, and Reliability Coordinators.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R6

This section to be completed by the Compliance Enforcement Authority

	Verify the entity implemented a process to ensure that Facility Ratings, System steady-state voltage limits and stability criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology.
	If the entity uses less limiting System Facility Ratings, System steady-state voltage limits and stability criteria than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology, verify the entity provided a technical justification to each of the required Transmission Planners, Planning Coordinators, and Reliability Coordinators.
Note to Auditor: Technical justification can be specific justification for a specific facility or broad based justification (e.g. upgrading a facility).	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

Registered Entity Response (Required):
Question: Does the entity have any Corrective Action Plans to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon that were required to be communicated as required? ☐ Yes ☐ No
If Yes, provide a list of the Corrective Action Plans. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested [i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Corrective Action Plans to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon
Evidence communication to each impacted Reliability Coordinator and Transmission Operator included Parts 7.1 through 7.5.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R7

This section to be completed by the Compliance Enforcement Authority

	Verify annual communication of Corrective Action Plans to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Reliability Coordinator and Transmission Operator.
	Verify the Corrective Actions Plans included:
	(7.1) The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);
	(7.2) The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);
	(7.3) The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);
	(7.4) The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;
	(7.5) The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.
Note to Auditor:	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Owner and Generation Owner. This communication shall include those Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

Registered Entity Response (Required):
Question: Has the entity identified instability, Cascading or uncontrolled separation in its Planning Assessment of the Near-Term Transmission Planning Horizon?
☐ Yes ☐ No
If Yes, provide a list of instances of instability, Cascading or uncontrolled separation identified in either the Planning Assessment of the Near-Term Transmission Planning Horizon. If No, explain how the entity made this determination.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence the entity communicated any instability, Cascading or uncontrolled separation identified in its Planning Assessment of the Near-Term Transmission Planning Horizon that adversely impacted the reliability of the Bulk Electric System to each impacted Transmission Owner and Generation Owner.
The entity's most recent Planning Assessment of the Near-Term Transmission Planning Horizon.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to FAC-014-3, R8

This section to be completed by the Compliance Enforcement Authority

	For each instance of instability, Cascading or uncontrolled separation identified in the entity's Planning Assessment of the Near-Term Transmission Planning Horizon that adversely impacted the reliability of the Bulk Electric System, verify the entity communicated the instability, Cascading or uncontrolled separation to each impacted Transmission Owner and Generation Owner.
	For all, or a sample of, communication from the entity to impacted Transmission Owners and Generation Owners, verify the communication included each of those owner's Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified.
Note to Auditor: Planning Coordinators are required to prepare a Planning Assessment of the Near-Term Transmission Planning Horizon in TPL-001-4 R2. The Facilities communicated to an owner are only required to be those facilities that impact the owner.	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.

The full text of STD-0XX-N may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	10/10/2017	NERC Compliance Assurance, RSAW Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1									X						
R2									X						
R3									X						
R4									X						
R5									X						
R6									X						
R7									X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from applicable FERC orders and other regulatory references. The FERC order cites are provided for ease of reference only, and this document does not necessarily include all applicable order provisions. In the event of a discrepancy between FERC orders, and the language included in this document, FERC orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Text entry area with white background:	Auditor-supplied information

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Operational Planning Analysis, including but is not limited to dated power flow study results.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R1
This section to be completed by the Compliance Enforcement Authority

	(R1) Review a sample of evidence and verify that the entity performs an Operational Planning Analysis, which determines if the planned operations for the next-day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Notes to Auditor:

1) The standard does not specify that a new daily Operational Planning Analysis (OPA) shall be performed. The entity may rely on an existing OPA if it is still valid for projected operating conditions. However, it would be valuable to understand in what situations the entity would not

perform a daily "next-day" analysis in order to assess whether planned operations will exceed SOLs or IROLs. **2)** For specific next-day analyses selected, consider how previous studies are validated, if used in place of conducting a unique next-day study for the specific next-day analysis selected?

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence, to demonstrate compliance.
Coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances.
Operational Planning Analyses performed in Requirement R1.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) Review a sample of Operating Planning Analyses and associated Operating Plans provided by the entity to verify that it has a coordinated plan for next-day operations that addresses potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances.
Note to Auditor: Based on the daily performance frequency of the Requirements R1 – R3 and R5. Sampling would typically be indicated to retrieve a valid sample across requirements R1-R3.	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Compliance (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated operator logs, e-mail records, or other evidence the entity notified impacted entities identified in the Operating Plans cited in Requirement R2 as to their role in the plans.
Coordinated Operating Plans for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances. (as requested based on sampling)

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R3
This section to be completed by the Compliance Enforcement Authority

	(R3) Review all or a sample of documentary evidence to determine if the entity notified all impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).
Note to Auditor: Sampling would typically be indicated to retrieve a valid sample for this requirement, but it could also be true that for the audit period there were no impacted entities which required notification.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated computer logs showing time the assessment was conducted, dated checklists, or other evidence.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R4
This section to be completed by the Compliance Enforcement Authority

	(R4) For all, or a sample of, BES events selected by the auditor, review evidence (dates and times in the audit period) and determine if the entity ensured a Real-time Assessment was performed at least once every 30 minutes.
Note to Auditor: Auditors are advised to monitor compliance with Requirement R4 during events, due to the importance of Real-time Assessments in such instances. Auditors can obtain a population of events for	

sampling from NERC's, or the Regional Entity's, records of mandatory event reports, other information available at the Regional Entities, or a query of the entity. Auditors are encouraged to monitor compliance during the most critical events on the entity's system occurring during the compliance monitoring period.

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed , in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

Compliance (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Results of a Real-time Assessment indicating an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance.
The entity's SOL methodology
Dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence demonstrating the entity notified, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
Associated Operating Plans.
If the results of a Real-time Assessment do not indicate actual or expected conditions that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance, the Reliability Coordinator may provide an attestation.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Interview entity representatives or review initial evidence to determine (for the compliance monitoring period) whether the entity's results of its Real-time Assessment(s) indicated an actual or expected condition that resulted in, or could have resulted in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
	(R5) If the results of the assessment above are negative (no determination of SOL or IROL exceedances for the audit period), attestations may be provided.
	(R5) Review a sample of evidence that supports the entity's assertion that it informed, in accordance with its SOL methodology, Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators of its actual or expected operations that result in, or could have resulted in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance.
Note to Auditor: Based on the daily performance frequency of Requirements R1 – R3 and R5, sampling would typically be indicated to retrieve a valid sample across Requirements R1-R3, inclusive of Requirement R5. Alternatively, R5 and R6 could be statistically sampled independent of R1-R3, if it was determined there were multiple instances where Real-time Assessments indicated actual or expected conditions that would or could have resulted in Reliability Coordinator Area SOL or IROL exceedance(s). The RC's SOL methodology identifies a risk based approach required in R7 for how SOL exceedances must be communicated and a time frame for which the SOL exceedance must be communicated.	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

Compliance (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's SOL methodology
When the SOL or IROL exceedance has been prevented or mitigated, provide documentation that the entity informed, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.
Dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence demonstrating the entity notified, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) Review submitted documentation to determine if the entity prevented or mitigated System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance(s) in Requirement R5. If, there were no such instances, review attestation from Requirement R5 asserting this fact.
	(R6) When the SOL or IROL exceedance was prevented or mitigated, review sample(s) of Requirement R5 evidence for supporting documentation that the entity notified impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators (if appropriate).
Note to Auditor: Where Requirement R5 evidence indicates possible SOL or IROL exceedances, the follow-up notification is specific to the condition of prevention or mitigation as indicated in Requirement R6. Meaning, review evidence to assure the entity notified (potentially) impacted entities of possible SOL or IROL exceedances (as identified in R5) that the possible SOL or IROL condition(s) was prevented or mitigated.	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

Compliance (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's SOL methodology
Evidence the entity used its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to IRO-008-3, R7

This section to be completed by the Compliance Enforcement Authority

	Verify the entity used its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard (to be made final)

The full text of IRO-008-3 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Regulatory Language (to be updated for -3)
Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Final Rule, Order No. 817, 153 FERC ¶ 61,178 (2015).

5. The Commission approved the initial TOP and IRO Reliability Standards in Order No. 693. On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.8 Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had "removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

13. Pursuant to section 215(d) of the FPA, we adopt our NOPR proposal and approve NERC's revisions to the TOP and IRO Reliability Standards, including the associated definitions, violation risk factors, violation severity levels, and implementation plans, as just, reasonable, not unduly discriminatory or preferential and in the public interest.

14. We also determine that the proposed TOP and IRO Reliability Standards should improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators.

17. Furthermore, the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs,

IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.

19. However, as we discuss below we direct NERC to modify the standards to include transmission operator monitoring of non-BES facilities, and to specify that data exchange capabilities include redundancy and diverse routing; as well as testing of the alternate or less frequently used data exchange capability, within 18 months of the effective date of this Final Rule.

58. We believe that proposed Reliability Standards TOP-002-4 and IRO-008-2 along with NERC's definition of reliability coordinator address NIPSCO's concern. Although the transmission operator and balancing authority develop their own operating plans for next-day operations, both the transmission operator and balancing authority notify entities identified in the operating plans as to their role in those plans. Further, each transmission operator and balancing authority must provide its operating plan for next-day operations to its reliability coordinator. In Reliability Standard IRO-008-2, Requirement R2, the reliability coordinator must have a coordinated operating plan for next-day operations to address potential SOL and IROL exceedances while considering the operating plans for the next-day provided by its transmission operators and balancing authorities. Also, Reliability Standard IRO-008-2, Requirement R3 requires that the reliability coordinator notify impacted entities identified in its operating plan as to their role in such plan. Based on the notification and coordination processes of Reliability Standards TOP-002-4 (for the transmission operator and balancing authority) and IRO-008-2 (for the reliability coordinator) for next-day operating plans, as well as the fact that the reliability coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, we believe that the reliability coordinator has the authority and necessary next-day operational information to resolve any next-day operational issues within its reliability coordinator area. Accordingly, we deny NIPSCO's request.

Selected Glossary Terms:

Please refer to the NERC web site for the current enforceable terms.

Specific Glossary terms suggested to be included in this RSAW:

Operating Instruction (effective 7/1/2016):

A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

Operational Planning Analysis (adopted 3/17/2011):

An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	07/20/2020	NERC Compliance Assurance, RSAWTF	New Document

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DRAFT Reliability Standard Audit Worksheet[1]

TOP-001-6 – Transmission Operations

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

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The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Applicability of Requirements

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R1										X		
R2	X											
R3	X	X		X								
R4	X	X		X								
R5		X		X						X		
R6		X		X						X		
R7										X		
R8										X		
R9	X									X		
R10										X		
R11	X											
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R23	X											
R24	X											
R25										X		

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Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
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Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence, which may include, but is not limited to, operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation that the Transmission Operator acted, or issued Operating Instructions, to maintain reliability within its Transmission Operator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R1

This section to be completed by the Compliance Enforcement Authority

	(R1) For an auditor selected sample of operating conditions that required action to maintain reliability,

	review evidence and verify the entity acted, or issued Operating Instructions, to maintain the reliability of its Transmission Operator Area.
Note to Auditor:	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence which may include, but is not limited to, dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that the entity acted, or issued Operating Instructions, to maintain reliability within its Balancing Authority Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) For an auditor selected sample of operating conditions that required action to maintain reliability, review evidence and verify the entity acted, or issued Operating Instructions to maintain the reliability of its Balancing Authority Area.
Note to Auditor:	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence demonstrating the entity complied with each Operating Instruction issued by its Transmission Operator(s), unless such action could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements.
If applicable, evidence demonstrating why the entity did not comply with the Transmission Operator's Operating Instruction.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R3

This section to be completed by the Compliance Enforcement Authority

	(R3) For all, or a sample of Operating Instructions selected by the auditor, review evidence and verify the entity complied with Operating Instructions issued by its Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

Registered Entity Response (Required):
Question: Did the entity receive an Operating Instruction from a Transmission Operator where compliance with the Operating Instruction could not be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements during the audit period?
☐ Yes ☐ No
If Yes, provide a list of Operating Instructions received from a Transmission Operator that could not be implemented and evidence of compliance with Requirement R4. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence demonstrating the entity informed its Transmission Operator of its inability to comply with its Operating Instruction, if the entity was unable to comply with the Operating Instruction.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) If the entity was unable to comply with the Operating Instruction(s), verify the entity informed the Transmission Operator(s) that it could not comply.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

Compliance Narrative (Required):

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence demonstrating that the entity complied with each Operating Instruction issued by its Balancing Authority, unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements.
If applicable, evidence demonstrating why the entity did not comply with the Balancing Authority's Operating Instruction.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) For all, or a sample of Operating Instructions selected by the auditor, review evidence and verify the entity complied with Operating Instructions issued by its Balancing Authority, unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

Registered Entity Response (Required):
Question: Did the entity receive an Operating Instruction from its Balancing Authority where compliance with the Operating Instruction could not be physically implemented or such actions would have violated safety, equipment, regulatory, or statutory requirements during the audit period?
☐ Yes ☐ No
Yes, provide a list of Operating Instructions received from a Balancing Authority that could not be implemented and evidence of compliance with Requirement R6. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence demonstrating that an entity informed its Balancing Authority of its inability to comply with its Operating Instruction, if the entity was unable to comply with the Operating Instruction.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) If the entity was unable to comply with the Operating Instruction(s), verify the entity informed its Balancing Authority that it could not comply.
Note to Auditor:	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Registered Entity Response (Required):
Question: Did the entity receive a request to provide assistance to another Transmission Operator during the audit period?
☐ Yes ☐ No
If Yes, provide a list such requests and state if the assistance was provided. If assistance was not provided, state the reasons such assistance was not provided. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. If no request for assistance was received, an attestation may be provided.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R7

This section to be completed by the Compliance Enforcement Authority

	(R7) For all, or a sample of requests for assistance selected by the auditor, review evidence and verify the entity assisted other Transmission Operators, if requested and able, in accordance with Requirement R7.
Note to Auditor:	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

Registered Entity Response (Required):
Question: Did the entity encounter any actual or expected operations that could have resulted in an Emergency, or that did result in an Emergency, during the audit period?
☐ Yes ☐ No
If Yes, provide a list of such instances and evidence of compliance. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of the actual or expected operations that result in, or could result in, an Emergency.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s)	Description of Applicability of Document

				or Section(s)	

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R8

This section to be completed by the Compliance Enforcement Authority

	(R8) Obtain a list of dates and times when the entity experienced actual or expected operations that resulted in, or could have resulted in, an Emergency.
	(R8) For all, or a sample of actual or expected operations that resulted in, or could have resulted in, an Emergency, review evidence to verify the entity informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators.
Note to Auditor:	

Auditor Notes:

R9 Supporting Evidence and Documentation

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
A list of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
Evidence that demonstrates that the entity notified its Reliability Coordinator and impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, telecommunication equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R9

This section to be completed by the Compliance Enforcement Authority

	(R9) For all, or a sample of outages selected by the auditor, review evidence and verify the entity notified its Reliability Coordinator and impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities..
Note to Auditor:	

Auditor Notes:

R10 Supporting Evidence and Documentation

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity monitored Facilities within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
Identification of Remedial Action Schemes within the entity's Transmission Operator Area.
Evidence to demonstrate the entity monitored the status of Remedial Action Schemes within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
Identification of non-BES facilities within the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Evidence to demonstrate the entity monitored non-BES facilities within the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Identification of status, voltages, and flow data for Facilities outside the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator

Area.
Evidence to demonstrate the entity monitored status, voltages, and flow data for Facilities outside the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Identification of Remedial Action Schemes statuses outside the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Evidence to demonstrate the entity monitored Remedial Action Schemes statuses outside the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Identification of status, voltages, and flow data for non-BES facilities outside the entity's Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Evidence to demonstrate the entity monitored status, voltages, and flow data for non-BES facilities outside the entity's Transmission Operator Area identified by the entity as necessary SOL exceedances within its Transmission Operator Area.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R10

This section to be completed by the Compliance Enforcement Authority

	(10.1) Verify the entity monitored Facilities within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
	(10.2) Verify the entity monitored the status of Remedial Action Schemes within its Transmission Operator Area for determining SOL exceedances within its Transmission Operator Area.
	(10.3) Verify the entity monitored non-BES facilities within its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.

	(10.4) Verify the entity obtained and utilized status, voltages, and flow data for Facilities outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
	(10.5) Verify the entity obtained and utilized the status of Remedial Action Schemes outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
	(10.6) Verify the entity obtained and utilized status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified by the entity as necessary for determining SOL exceedances within its Transmission Operator Area.
Note to Auditor: TOP-003-3 Requirement R1 specifies that the Transmission Operator shall develop a data specification which includes data and information needed by the Transmission Operator to support its Operation Planning Analyses, Real-time monitoring, and Real-time Assessments. This includes non-BES data and external network data as deemed necessary by the Transmission Operator	

Auditor Notes:

R11 Supporting Evidence and Documentation

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Compliance Narrative (Required):

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
A list of Remedial Action Schemes within the entity's Balancing Authority Area that impact generation or Load.
Evidence to demonstrate the entity monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R11

This section to be completed by the Compliance Enforcement Authority

	(R11) Verify the entity monitored its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
Note to Auditor:	

Auditor Notes:

R12 Supporting Evidence and Documentation

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified IROL, the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Registered Entity Response (Required):
Question: Did the entity exceed an identified IROL for any period of time during the audit period?
☐ Yes ☐ No
If Yes, provide a list of IROL exceedances. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
A list of IROLs with the associated IROL T_v.
Evidence to demonstrate that for any occasion in which the entity operated outside any identified IROL, the continuous duration did not exceed its associated IROL Tv.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R12

This section to be completed by the Compliance Enforcement Authority

	(R12) For all, or a sample of IROL exceedances selected by the auditor, verify the entity did not operate outside any IROL for a continuous duration exceeding its associated IROL T_v.
Note to Auditor:	

Auditor Notes:

R13 Supporting Evidence and Documentation

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Registered Entity Response (Required):
Question: During the audit period, did the entity experience a loss in Real-time Assessment capability?
☐ Yes ☐ No
If Yes, explain how the entity ensured a Real-time Assessment was performed at least once every 30 minutes during this loss. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity ensured a Real-time Assessment was performed at least once every 30 minutes.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R13

This section to be completed by the Compliance Enforcement Authority

	(R13) Verify the Transmission Operator ensured a Real-time Assessment was performed at least once every 30 minutes.
Note to Auditor: See definition of Real-time Assessment in Selected Glossary Terms section of RSAW and the rationale for R13 in the Rationale section of the Standard.	

Auditor Notes:

R14 Supporting Evidence and Documentation

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their RC, Operating Procedures, Operating Processes, operating policies, binding constraint logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc).

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Operating Plans for SOL exceedances as required under TOP-002-4 R2.
Evidence to demonstrate the entity initiated its Operating Plan to mitigate identified SOL exceedances. For SOL exceedances as defined in FAC-011 R7.2 which were successfully mitigated, system logs/records showing the SOL exceedance successfully mitigated in conjunction with general operating policies and procedures can be considered as sufficient evidence. For other categories of exceedances as defined in FAC-011 R7.1 some additional evidences may be required to demonstrate that the Operating Plan was initiated, such as operator logs, phone logs, generation redispatch logs, facility specific standing operating guides, or switching logs.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R14

This section to be completed by the Compliance Enforcement Authority

	(R14) For all, or a sample of SOL exceedances identified as part of the entity's Real-time monitoring or Real-time Assessment, verify the entity initiated its Operating Plan to mitigate the SOL exceedance.
Note to Auditor: Transmission Operators are required to have an Operating Plan(s) for next-day operations in TOP-002-4 R2.	

Auditor Notes:

R15 Supporting Evidence and Documentation

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology.

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity informed its Reliability Coordinator of its actions to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R15

This section to be completed by the Compliance Enforcement Authority

	(R15) For all, or a sample of instances when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology, verify the entity informed its Reliability Coordinator of its actions to return the System to within limits.
Note to Auditor:	

Auditor Notes:

R16 Supporting Evidence and Documentation

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity provided its System Operators with the authority to approve planned outages of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R16

This section to be completed by the Compliance Enforcement Authority

	(R16) Verify the entity provided its System Operators with the authority to approve planned outages of

	its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
Note to Auditor: This authority can also be confirmed during System Operator interview questions.	

Auditor Notes:

R17 Supporting Evidence and Documentation

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities and associated communication channels between affected entities.

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities and associated communication channels between affected entities.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity provided its System Operators with the authority to approve planned outages of its telemetering and control equipment, monitoring and assessment capabilities and associated communication channels between affected entities.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R17

This section to be completed by the Compliance Enforcement Authority

	(R17) Verify the entity provided its System Operators with the authority to approve planned outages of its

	telemetering and control equipment, monitoring and assessment capabilities and associated communication channels between affected entities.
Note to Auditor: This authority can also be confirmed during System Operator interviews.	

Auditor Notes:

R18 Supporting Evidence and Documentation

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Registered Entity Response (Required):
Question: Did the entity experience an instance where there was a difference in SOLs during the audit period?
☐ Yes ☐ No
If Yes, provide a list of such instances. If No, describe how this was determined in the narrative section below. [Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence to demonstrate the entity operated to the most limiting parameter in instances where there was a difference in SOLs.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R18

This section to be completed by the Compliance Enforcement Authority

	(R18) For an auditor selected sample of instances where there was a difference in SOLs, verify the entity operated to the most limiting parameter.
Note to Auditor:	

Auditor Notes:

R19 Supporting Evidence and Documentation

R19. Reserved.

M19. Reserved.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R19
This section to be completed by the Compliance Enforcement Authority

Note to Auditor:	

Auditor Notes:

R20 Supporting Evidence and Documentation

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Identification of the Reliability Coordinators, Balancing Authorities, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.
Identification of data exchange capabilities with the Reliability Coordinators, Balancing Authorities, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.
Evidence that data exchange capabilities include redundant and diversely routed data exchange infrastructure within the entity's primary Control Center for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R20

This section to be completed by the Compliance Enforcement Authority

	(R20) Verify the entity has data exchange capabilities with the Reliability Coordinators, Balancing Authorities, and other entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments.
	(R20) Verify that data exchange capabilities have redundant and diversely routed data exchange infrastructure within the entity's primary Control Center.

Note to Auditor:

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. Additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components is not required.

TOP-003-3 requires the Transmission Operator to have a data specification for all the data it needs to perform its Real-time Assessment and Real-time monitoring.

Auditor Notes:

R21 Supporting Evidence and Documentation

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality.

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Registered Entity Response (Required):
Question: Were any of the data exchange capability tests unsuccessful?
☐ Yes ☐ No
If Yes, provide a list of such instances and evidence of compliance. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Identification of data exchange capabilities specified in Requirement R20.
Evidence that the entity tested its data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality, at least once every 90 calendar days.
Evidence that for each unsuccessful test, the entity initiated action within two hours to restore redundant functionality.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R21

This section to be completed by the Compliance Enforcement Authority

	(R21) Verify the entity tests its data exchange capabilities specified in Requirement R20 for redundant functionality, or experienced an event that demonstrated the redundant functionality, at least once every 90 calendar days.
	(R21) Verify that for each unsuccessful test, the entity initiated action within two hours to restore redundant functionality.

Note to auditor: A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Auditor Notes:

R22 Supporting Evidence and Documentation

R22. Reserved.

M22. Reserved.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R22
This section to be completed by the Compliance Enforcement Authority

Note to Auditor:	

Auditor Notes:

R23 Supporting Evidence and Documentation

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions.

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform it Real-time monitoring and analysis functions as specified in the requirement.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Identification of the Reliability Coordinators, Transmission Operators, and other entities the entity has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions.
Identification of data exchange capabilities with the Reliability Coordinators, Transmission Operators, and other entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions.
Evidence that data exchange capabilities include redundant and diversely routed data exchange infrastructure within the entity's primary Control Center.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R23

This section to be completed by the Compliance Enforcement Authority

	(R23) Verify the entity has data exchange capabilities with the Reliability Coordinators, Transmission Operators, and other entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions.
	(R23) Verify that data exchange capabilities have redundant and diversely routed data exchange infrastructure within the entity's primary Control Center.
Note to Auditor: Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center. The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. Additional redundant data exchange infrastructure components solely to provide for redundancy during planned or unplanned outages of individual components is not required. TOP-003-3 requires the BA to have a data specification for all the data it needs for performing its analysis functions and Real-time monitoring.	

Auditor Notes:

R24 Supporting Evidence and Documentation

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality.

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

Registered Entity Response (Required):
Question: Were any of the data exchange capability tests unsuccessful?
☐ Yes ☐ No
If Yes, provide a list of such instances and evidence of compliance. If No, describe how this was determined in the narrative section below.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
Identification of data exchange capabilities specified in Requirement R23.
Evidence that the entity tested its data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality, at least once every 90 calendar days.
Evidence that for each unsuccessful test, the entity initiated action within two hours to restore redundant functionality.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R24

This section to be completed by the Compliance Enforcement Authority

	(R24) Verify the entity tests its data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality, at least once every 90 calendar days.
	(R24) Verify that for each unsuccessful test, the entity initiated action within two hours to restore redundant functionality.

Note to auditor:
A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Auditor Notes:

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology , Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings, or electronic communications.

Compliance Narrative (Required):
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested: Error! Bookmark not defined.

Provide the following evidence, or other evidence to demonstrate compliance.
The applicable Reliability Coordinator's SOL methodology
Evidence that the entity used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TOP-001-6, R25

This section to be completed by the Compliance Enforcement Authority

	(R25) Verify that the entity used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis.
Note to auditor:	

Auditor Notes:

Additional Information: Supporting Evidence and Documentation

Reliability Standard (to be included with final posting)

The full text of TOP-001-6 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

Regulatory Language (to be updated before final posting)
***North American Electric Reliability Corp.*, Unpublished Letter Order in Docket No. RR17-4-000 (Apr. 17, 2017)**.

Proposed Reliability Standard TOP-001-4, Requirement R10 has been revised to require the transmission operator to monitor non-BES facilities for determining system operating limit exceedances within its transmission operator area, as directed by the Commission in Order No. 817. NERC states that this revision helps to ensure that all facilities that can adversely impact reliability are monitored. NERC also revised proposed Reliability Standard TOP-001-4 to require that the operator's and balancing authority's data exchange capabilities for the exchange of realtime data needed for real-time monitoring and analysis have redundant and diversely routed data exchange infrastructure within the entity's primary control center and that these capabilities be tested for redundant functionality on a regular basis. Similar revisions are reflected in Reliability Standard IRO-002-5 to clarify the obligations of the reliability coordinator. NERC states that these modifications help support reliable operations by preventing a single point of failure in primary control center data exchange infrastructure from halting the flow of real-time data used by operators to monitor and control the BES.
NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), effective as of the date of this order.

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Final Rule, Order No. 817, 153 FERC ¶ 61,178 (2015).

5. The Commission approved the initial TOP and IRO Reliability Standards in Order No. 693.[3] On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.[4] Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had "removed critical reliability aspects that are

[3] See Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 508, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007). In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards. Mandatory Reliability Standards for Interconnection Reliability Operating Limits, Order No. 748, 134 FERC ¶ 61,213 (2011).
[4] On April 5, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources.

included in the currently-effective standards without adequately addressing these aspects in the proposed standards." The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

14. We also determine that the proposed TOP and IRO Reliability Standards should improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators. The proposed TOP Reliability Standards will eliminate multiple TOP standards, resulting in a more concise set of standards, reducing redundancy and more clearly delineating responsibilities between applicable entities. In addition, we find that the proposed Reliability Standards provide a comprehensive framework as well as important improvements to ensure that the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. The TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions.

17. Furthermore, the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs, IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.

19. However, as we discuss below we direct NERC to modify the standards to include transmission operator monitoring of non-BES facilities, and to specify that data exchange capabilities include redundancy and diverse routing; as well as testing of the alternate or less frequently used data exchange capability, within 18 months of the effective date of this Final Rule.

35. Indeed, once a non-BES facility is included in the BES definition under the BES exception process, the "non-BES facility" becomes a BES "Facility" under TOP-001-3, Requirement R10, and real-time monitoring is required of "Facilities." However, we are concerned that in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap. As the 2011 Southwest Outage Report indicates, the Regional Entity "should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in [real-time contingency analysis] systems." Such monitoring of non-BES facilities could provide a "stop gap" during the period where a sub-100 kV facility undergoes analysis as a possible BES facility, allowing for monitoring in the interim until such time the non-bulk electric system facilities become "BES Facilities" or the transmission operator determines that a non-bulk electric system facility is no longer needed for monitoring to determine a system operating limit exceedance in its area. We believe that the operational planning analyses and real-time

assessments performed by the transmission operators as well as the reliability coordinators will serve as the basis for determining which "non-BES facilities" require monitoring to determine system operating limit and interconnection reliability operating limit exceedances. In addition, we believe that monitoring of certain non-BES facilities that are occasional system operating limit exceedance performers may not qualify as a candidate for inclusion in the BES definition, yet should be monitored for reliability purposes. Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary. NERC can develop an equally efficient and effective alternative that addresses our concerns.

47. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations. NERC's comprehensive approach to establishing communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, we direct NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.

55. With regard to clarification of emergencies in Reliability Standard TOP-001-3, Requirement R8, we do not see a need to modify the language…the requirement as written implies that the transmission operator has discretion to determine what could result in an emergency, based on its experience and judgment. In addition, we note that the transmission operators' required next-day operational planning analysis, real-time assessments and real-time monitoring under the TOP Reliability Standards provide evaluation, assessment and input in determining what "could result" in an emergency.

60. Rather, we believe that, because the reliability coordinator is required to have a coordinated operating plan for the next-day operations, the reliability coordinator will perform its task of developing a coordinated operating plan in good faith, with inputs not only from its transmission operators and balancing authorities, but also from its neighboring reliability coordinators. A reliability coordinator has a wide-area view and bears the ultimate responsibility to maintain the reliability within its footprint, "including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations."

65. Reliability Standard TOP-001-3, Requirement R13 requires the transmission operator to ensure the assessment is performed at least once every 30 minutes, but does not state that the transmission operator on its own must perform the assessment and does not specify a system or tool. This gives the transmission operator flexibility to perform its real-time assessment. Further supporting this flexibility, NERC's definition of real-time assessment states that a real-time assessment "may be provided through internal systems or

through third-party services." Therefore, we believe that Reliability Standard TOP-001-3, Requirement R13 does not specify the system or tool a transmission operator must use to perform a real-time assessment. In addition, NERC explains that Reliability Standard TOP-001-3, Requirement R13 and the definition of real-time assessment "do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa." Accordingly, we conclude that TOP-001-3 adequately addresses NIPSCO's concern, namely, if a transmission operators' tools are unavailable for 30 minutes or more, the transmission operator has the flexibility to meet the requirement to assess system conditions through other means.

69. In its SOL White Paper, NERC stated that the intent of the SOL concept is to bring clarity and consistency for establishing SOLs, exceeding SOLs, and implementing operating plans to mitigate SOL exceedances.56 In addition, "transient stability ratings" are included in the SOL definition. Further, in the SOL White Paper, NERC states that the "concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2 and FAC-014-2."

70. With respect to Reliability Standard TOP-001-3, we agree with NERC that Requirement R13 specifies that transmission operators must perform a real-time assessment at least once every 30 minutes, which by definition is an evaluation of system conditions to assess existing and potential operating conditions. The real-time assessment provides the transmission operator with the necessary knowledge of the system operating state to initiate an operating plan, as specified in Requirement R14, when necessary to mitigate an exceedance of SOLs. In addition, the SOL White Paper provides technical guidance for including timelines in the required operating plans to return the system to within prescribed ratings and limits. Accordingly, we conclude that the establishment of transient stability operating limits is adequately addressed collectively through proposed Reliability Standard TOP-001-3, currently-effective Reliability Standards FAC-011-2 and FAC-014-2 and NERC's Glossary of Terms definition of SOLs.

Selected Glossary Terms

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operation Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Plan: A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	7/7/2020	NERC Compliance Assurance, RSAW Task Force	New Document for project page

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

NERC
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RELIABILITY CORPORATION

EXTENDED

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Comment Period, Initial/Additional Ballots, and Non-binding Polls Now Open through August 26, 2020

Now Available

Recognizing the age of the project, NERC staff have reviewed the ballot pools that were formed in 2017 and 2018. Additionally, six non-binding polls did not reach quorum. Therefore, the comment period, initial/additional ballots, and non-binding polls, have been re-opened through **8 p.m. Eastern, Wednesday, August 26, 2020** for the following standards and implementation plan:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 – Transmission Operations
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- Implementation Plan

Commenting and Balloting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*

- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

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UPDATED
Standards Announcement
Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through August 3, 2020
Ballot Pools Formed through July 20, 2020

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, August 3, 2020** for the following standards and implementation plan:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Monday, July 20, 2020.** ***NERC staff made the decision to re-open the older, existing ballot pools to allow stakeholders to join if desired.*** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*

- *Passwords expire every **6 months** and must be reset.*
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- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial and additional ballots for the standards and implementation plan, along with non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 24 – August 3, 2020**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

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Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

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The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

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Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, July 20, 2020** only for the newly added standards/initial ballots**.** Registered Ballot Body members can join the ballot pools here.

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Next Steps

Initial and additional ballots for the standards and implementation plan, along with non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 24 – August 3, 2020**.

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Comment Report

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	6/19/2020
Comment Period End Date:	8/26/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 3 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 3 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 3 OT 2015-09 Establish and Communicate System Operating Limits IRO-008-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-002-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 AB 2 ST 2015-09 Establish and Communicate System Operating Limits TOP-001-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 173 different people from approximately 119 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy- FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC

					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					John Hasting	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc	2	MRO
					Tim Miller	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					will Tootle	Southwest Power Pool Inc.	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

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John Allen - City Utilities of Springfield, Missouri - 4

Answer	No
Document Name	

Comment

I agree SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. However, the standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. Otherwise it becomes more of a guideline that is difficult to enforce. It appears each Reliability Coordinator has some flexibility to develop it's own method for identifying SOL exceedances in its SOL methodology. If so, then what is going to prevent two adjacent Reliability Coordinators from arriving at different conclusions and having disagreements during Real-time operations? What is going to prevent two adjacent Transmission Operators in different Reliability Coordinator Areas from having disagreements? What is going to prevent disagreements between Registered Entities and their Regional Entity? How are those disagreements resolved? The purpose of the SOL Whitepaper was to establish a common understanding of SOL exceedances across North America. Hopefully these requirements are not detrimental to that effort and the purpose of this project.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No

Document Name	
Comment	

In consideration of past confusion related to whether an SOL exceedance is a regulatory violation, LES suggests the following changes to better clarify R6:

R6.2.1 Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. *[Remove: Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.]*

R6.2.3 Predetermined stability limits are not exceeded. *[Remove: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.]*

Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	

R6.1: The way this is worded is awkward and confusing. Why are you using the language "no contingencies" instead of "pre-contingency state"?

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	No
Document Name	
Comment	
FMPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA suggests the proposed TOP-001-6 requirement R25 be removed. BPA believes the requirement that the TOP use the RC SOL methodology for establishing SOLs in the Operations horizon is already covered in FAC-014 R2. The proposed FAC-011-4 R6 will require the RC SOL Methodology to explicitly include applicability to "Real-time monitoring, Real-time Assessments, and Operational Planning Analysis". (Using the RC West SOL Methodology as an example, the applicability of the methodology to these sub-horizons is already explicit in the document.) BPA believes the proposed TOP-001-6 R25 is redundant and simply adds to the burden of compliance documentation. BPA has no concerns with the proposed revisions to IRO-008-3 R5/R6.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE appreciates the standard drafting team's (SDT) efforts to clarify System Operating Limit (SOL) exceedance use and determination. As Texas RE understands it, proposed FAC-011-4 Requirement R6 establishes the required system performance framework in an RC's SOL methodology for determining SOL exceedances in the RC's Real-time monitoring, Real-time Assessment (RTA) and Operation Planning Analyses (OPA)	

activities. Texas RE remains concerned, however, that proposed FAC-011-4 could be read to permit the broader use of less conservative Facility Ratings in identifying and responding to SOL exceedances by permitting entities to operate the system without identifying an SOL and implementing an Operating Plan when: (1) pre-contingency steady state flows are within Emergency Ratings in circumstances in which System adjustments to return the flow to within a Facility's Normal Rating could be executed and completed within the applicable time duration of the Emergency Ratings; and (2) post-contingency flows through Facilities are within the Facility's highest Emergency Rating.

Regarding post-contingency flows in particular, Texas RE is concerned that entities would not be required to identify post-contingency flows and voltages above a Facility's two-hour Emergency Rating as an SOL. Texas RE notes that the "highest Emergency Rating" is usually an extreme limit associated with a very short duration to mitigate an exceedance of the Emergency Rating. For example, ERCOT ISO utilizes a 15-minute rating (along with 2-hour and continuous) that is defined as shown below:

"The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current."

As Texas RE reads the proposed FAC-011-4, R 6.2.1 language, SOL methodologies could be designed to permit post-contingency flows above a Facility's two-hour Emergency Rating but below the highest 15-minute rating. By possibly not requiring entities to identify this instance as an SOL exceedance in its OPA or RTA, an entity would correspondingly not be required to create an Operating Plan to mitigate the exceedance and would not be required to take pre-emptive steps to address such post-contingency flows identified in Real-time. In turn, if an Operating Plan is not created, the entity potentially would not know the adjustments needed to address the exceedance and the duration in which these adjustments can be completed.

Texas RE observes that the proposed NERC System Operating Limit Definition and Exceedance Clarification provides: "Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event."

Texas RE supports this approach, but believes additional clarity is necessary in the Standard Requirement language itself to require entities more proactive action to address post-contingency identified Emergency Rating exceedances rather than only requiring entities to develop Operating Plans when exceedances of the highest Emergency Rating are identified.

Additionally, Texas RE recommends the SDT consider the following:

- In Part 6.1, rephrase "System performance for no Contingencies demonstrates the following to "System performance **where there are no applied** Contingencies demonstrates the following". Alternatively, "applied" could be moved to be after "Contingencies".
- In Part 6.1.2, there is typically no time duration associated with voltage limits, nor is there a reference to time duration in the proposed definition of System Voltage Limits. Based on this language it should or a SOL exceedance for a System Voltage Limit may not occur based on this language. The reliability of the grid could suffer by never returning to "normal" System Voltage Limits because no time duration is specified.

- In Part 6.2.1 “Steady State” is capitalized (and also capitalized in the rationale document in several places), but there is no current or proposed definition in the NERC Glossary. Texas RE has experienced entities asking about a definition during recent engagements.
- Additionally, within Part 6.2, there may need to be a reference regarding “Predetermined stability limits are not exceeded”. It would appear that the omission would allow a “predetermined stability limit” to be exceeded for a single contingency and thus meet system performance, which seems to contradict an N-1 approach to reliable operations.
- Part 6.1.2 states “System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.” The proposed definition of System Voltage Limit does not define a time period. So there nothing to describe what the “specified time duration of those emergency System Voltage Limits” is. Texas RE recommends the System Voltage definition include a time duration to be more effective, reliable, and applicable.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 1.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports the comments provided by EEI:

While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring "predetermined stability limits" to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the "stable performance criteria defined in the Reliability Coordinator's SOL methodology" to be met, based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2.

Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.

Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring “predetermined stability limits” to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the “stable performance criteria defined in the Reliability Coordinator’s SOL methodology” to be met, based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2.

Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.

Likes 0	
Dislikes 0	
Response	

Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
ACES believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA partially agrees with the SDT revisions that address how SOL exceedances are determined and used in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. The flexibility afforded to each Reliability Coordinator to determine its own framework based upon its SOL methodology is an absolute must, but the concept of "a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments" is problematic and vague. It is noted that the concept of a "risk-based approach" does not carry over into the actual selection of single or multiple Contingency events which is a core tenet of the existing FAC-011-3. Incorporating aspects of risk are essential to the establishment of SOL exceedances (e.g., defining credible multiple contingencies) and should be addressed in each Reliability Coordinators SOL methodology, but this perpetuates the confusion that has plagued the existing FAC-011-4 and elsewhere.

Likes 0	
Dislikes 0	
Response	

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	

FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes.

PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.

Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

While FAC-011-4 requires the RC to Provide Planning Coordinators and Transmission Planners with the RC Methodology, FAC-014-3 does not allow the Planning Coordinators and Transmission Planners to respond to the RC established SOLs and requirese the Planning Coordinators and Transmission Planners to establish their own SOLs that are equally limiting or more limiting than the RC established SOLs.

What if there is a technical problem with the RC established SOLs. There is not listed recourse in FAC-014-3 for the PC or the TP to provide comments on technical problems with the RC established SOLs and a requirement that the RC address those problems.

Clark Public Utilities is a small utility and as a TP, it doubts that the RC West is going to be very concerned about Clark's small area of 115 kV transmission. RC West has already informed Clark by email that it will only be in direct contact with its BA and TOP members and Clark need to go through its TOP (Bonneville Power Administration) to deliver its annual Transmission Planning Assessment. FAC-011 and FAC-014 need to address the changed relationship between non-BA and non-TOP entities in the West that are part of the RC West Reliability Coordinator footprint.

RC West's relationship with non-BAs and non-TOPs is different that the Peak RC relationship, RC West seems only to want to deal directly with the larger organizations. While this may only be a situation in the West, NERC should look closer at what the RC to other entity relations should be so the overall compliance can be more efficient and so that smaller entities are not creating work that is not going to be used. That is just paper pushing to make sure a compliance box is checked off and is not doing anything to assure reliability.

Clark believes that the relationship heirarchy for the Operating Horizon should be from the RC to the Planning Coordinator to the Transmission Planner. The Planning Coordinator should develop its SOL Methodology using the RC Methodology and RC Contingincies for the Operating Horizon and its own methodology and its own contingencies for the Planning Horizon. The PC should distribute its methodology and contingency list to Transmission Planners in its footprint. TPs then should have the ability to coordinate their own contingincies with the PC provided contingincy list. Once that is done (i.e. the TP and PC agree on the contingencies to be used in studies) the TP should then establish its SOLs for the Operating Horizon and Planning Horizion and provide those to its PC for comments and revision or approval. The PC should provide its consoldated SOLs for the Operating Horizon and Planning Horizion to the RC for comments and revision or approval. Then the RC should provide the final approved list of SOLs for all PCs and TPs in its footprint to all TOPs in its footprint.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment

FAC-014-3 No

The FAC-014-3 R6 language opens the door for the Reliability Coordinator (RC) to dictate to the Transmission Planner (TP), through the RC's SOL methodology, the following items used in planning assessments: facility ratings, voltage criteria, and stability criteria. Establishment of facility ratings are the responsibility of the TO under FAC-008, while establishment of voltage and stability criteria are the responsibility of the TP under TPL-001-4. These responsibilities should not be ceded to another party. Long term implications are that the RC, through control of such items as facility ratings, voltage and stability limits, could force a TO to enter into corrective action plans and associated capital expenditures that they otherwise would not.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint.

However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	
Comment	

MEC supports the MRO NSRF comments.

The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint.

However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	
Comment	

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Please see our comments in Q#2 and Q#4

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Dominion Energy supports comments submitted by EEI. Dominion agrees that the implmentation period should be extended to allow entities the appropriate time to make changes to complex systems and processes.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	Yes
Document Name	

Comment

OGE agrees with MRO-NSRF’s comments on replacing IROL definition language with “Adverse Reliability Impact” as shown below:

Proposed Language:

FAC-011-4, Parts 6.1.4 and 6.2.4. Adverse Reliability Impacts do not occur. 1

Footnote 1, page 5: Stability evaluations and assessments of Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that Adverse Reliability Impacts do not occur.

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of Adverse Reliability Impacts

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	Yes
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

ATC appreciates the changes made by the SDT to address industry concerns and we are supportive of the current revisions to these standards. We do recommend one change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although we understand the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

Likes 0	

Dislikes 0	

Response

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter

Answer	Yes
Document Name	

Comment

FAC-014-3 The statement “any instability identified in its Planning Assessment of the Near-Term Transmission…” seems unclear. I think an improvement and more clear statement might be, “any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…”.

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	Yes
Document Name	

Comment

We agree with the revisions but offer the following for consideration and improvement.

a. Requirement R7 – plural word “communications” needs to be changed to be singular.

b. The proposed modification to IRO-008 requirement R6 effectively requires the RC to notify TOPs and BAs when SOL exceedances have been mitigated or prevented in accordance with its SOL Methodology; however, there is no specific requirement in proposed FAC-011-4 that requires the SOL methodology to address notification of SOL exceedance mitigation or prevention. It only specifically requires the SOL methodology to addresses notification of SOL exceedances. While it is true that proposed FAC-011-4 requirement R7 can be interpreted to include not only notification of SOL exceedances, but also notification of SOL exceedance mitigation or prevention, it might be clearer to enhance FAC-011-4 requirement R7 by specifically addressing notification of SOL exceedance mitigation and prevention. If this modification is not made, RCs might not know that their SOL methodology is supposed to address notification of SOL exceedance mitigation and prevention if they don’t happen to read proposed IRO-008 requirement R6. Potential language enhancement could be “Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances (and associated exceedance mitigation) identified as part of Real-time monitoring and Real-time Assessments must be communicated…”

Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We believe the future for SOL communication will require automation for exceedances to be logged and reported, as based on RC and TOP methodology. We have concerns with an increase in data logging requirements and ask the SDT to look at TOP-001 and we question whether it is the best place for specifications for determining real-time assessments? Perhaps it is better in TOP-002? Also we believe an SOL needs to be clearly defined and not open to interpretation from region to region. In addition, we believe that a 12 month implementation plan wouldn't allow enough time to incorporate these new changes, to procure hardware and software, and therefore we ask that a 30 month implementation plan be implemented.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	

Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports the direction of the changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. However, the implementation plan should be extended to account for the additional work by responsible entities to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to track accurately exceedances and validate exceedances. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.

ITC believes however that in a similar way that industry responded to FAC-015, the same concerns exist for FAC-014-3 R7. Transmission Planners refer to TPL-001-4 (-5). It seems misplaced to have a requirement concerning the Near Term Assessment and its results in a FAC-014 standard.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3

Answer	Yes
Document Name	

Comment

IPL offers no further comments.

Likes 0	
Dislikes 0	

Response

Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Oncor supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination. That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding. Proposed revision to **FAC-011-4, Part 6.4**: "planned manual load shedding is acceptable only after all available System adjustments have been ***assessed*** (delete made)." Note: SPP was not party to the comment for Question #1.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination.

That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding.

Proposed revision to **FAC-011-4, Part 6.4**: "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	
Comment	

California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	Yes
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes.

PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.

Likes 0	
Dislikes 0	

Response

Maurice Paulk - Cleco Corporation - 1,3,5,6

Answer	Yes
Document Name	

Comment	
See SEE, EEI and MISO comments.	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

Jack Stamper - Clark Public Utilities - 3

Answer	No
Document Name	

Comment

No. FAC-014 is administratively burdonsome on small entites by requiring it to accept RC established SOLs without any recourse to address technical problems with the RC established SOLs. It the RC is going to establish and communicate SOLS to a PC or a TP, there should be the ability for the PC or the TP to provide comments and a requirement for the RC to address those comments.

A better approach is discribed in Clark's answer to Question 1. Pay more attention to the changes that are occuring in the west (and maybe elsewhere). The RC is more eficient when dealing with larger entities (BAs, TOPs, and PCs). PCs should be the driving entity for work performed by TPs in the PC footprint. PCs establish the SOL Methodology (using the RC methodology for the Operings Horizon) used by its TPs,and would then consolidate its planning study results with the approved TP planning study results. The PC would then provide the consolidated results to the RC who would in turn provide the approved final SOL list to its TOPs'

Likes 0	
Dislikes 0	

Response

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No

Document Name	
Comment	

WAPA partially agrees with the SDT revisions that address how SOL exceedances are identified and communicated, but we do not agree with how the definitions of SOL versus SOL exceedances have been confused in FAC-011-4, specifically in Requirement R6 to include a performance framework in the Reliability Coordinator SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses. We request that the SDT reconsider that the constraints that define how SOLs are established are categorically different than how exceedances are defined, identified in the Operations Horizon, and communicated.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT is concerned that the meaning of "communicated" in Requirement R7 is not sufficiently clear. ERCOT suggests that Requirement R7 be revised in order to clarify that communications may be electronic. Similar to the measures accompanying IRO-008, Requirement R5, and TOP-001, Requirement R15, Requirement R7 should be revised to expressly permit electronic communications. Moreover, ERCOT believes "electronic" communications should be defined to include the mere electronic posting of data that enables entities to access/view SOL exceedances.

ERCOT further notes that it intends to vote in favor of FAC-011-4, provided Requirement R7 is clarified to provide that communications may be electronic.

Likes 0	

Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

FAC-011-4 R7

FAC-011-4 R7 implies the use of a “risk-based” approach for the communication aspects of R7.1.1 through R7.2.2.

“Risk-based” approach terminology is rare outside of FAC vegetation. As written, this terminology could result in compliance misinterpretation or misunderstanding by operations staff.

FAC Standards address the methodology of determining SOLs, COM Standards address the communication protocol between operations, and IRO Standards address interconnected operations of the Bulk Electric System (BES) including coordination with external entities.

The SPP Standards Review Group asks the SDT’s consideration that R7 should not be a Requirement in the FAC Standards, instead, included with the IRO Standards where it would be intuitive for operations staff to reference.

IRO-008-3 R5

IRO-008-3 R5 provides expectations of operations staff in real-time communication requirements needed to facilitate reliability. This Standard is intentionally, and properly, non-prescriptive in specific aspects of real-time or anticipated SOL risks, and does not introduce “risk-based” prescriptive actions for specific SOL events.

The SPP Standards Review Group considers IRO-008-3 R5 sufficient in requiring coordination and communication between entities that take place during SOL and IROL events. If necessary to document SOL methodologies that include the communication and coordination during such events, the SPP Standards Review Group recommends the methodologies should not be more descriptive than IRO-008-3 R5.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

Requirement R7 of FAC-011-4 as currently written only provides the ability for a “risk based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated”, it does not seem to provide a risk based approach to how SOL exceedances are identified. If the intent is to provide the ability to use a risk based approach to determine how SOL exceedances are identified the language should be modified to make this clear. Requirement R7 could be reworded to say:

“Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments and how they must be communicated and if so, the timeframe that communications must occur.”

If it is not the intent of the SDT to allow the identification of SOL exceedances to be risk based, requirement R7 may provide some relief from communication requirements that could be burdensome depending on the Reliability Coordinators’s SOL methodology, however it does not change that fact that Requirement 6 now makes any post contingent flow projected above a Facilities highest Emergency Rating an SOL exceedance. Some existing SOL methodologies allow for post contingent mitigation actions to be developed within 30 minutes in order to prevent this situation from becoming an SOL exceedance. It does seem appropriate that post contingent flow above the highest emergency rating would be an SOL exceedance, however this would be more stringent than what some have today and require more tracking, documentation, and communication. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

In our opinion a 30 month implementation would be better because an entity may need to purchase new servers, or hardware, and software to meet logging obligations. We are concerned with the burden of providing exceedances due to the level of detail required from our ISO that will also become our responsibility. We believe that a large amount of work will be required to document and log what is expected to be a much larger number of exceedances under the proposed new FAC-011-04 and TOP-001-6 Reliability Standards.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment	
The Evergy companies do not support the proposed revision to FAC-011-4, TOP-001-6 and IRO-008-3 to address compliance risk and administrative logging. The revisions are ambiguous and proposed requirements unsustainable. There is inconsistency between R6.2 and R6.2.1, with the proposed language being confusing. Moreover, having both Normal Ratings and Emergency Ratings calculated under FAC-008, and, also, entities being required to use both Normal Ratings and Emergency Ratings, is concerning: The revision would require operating at an Emergency Rating for a specified amount of time "*under a no contingency scenario*" rather than the current practice of operating up to an emergency rating indefinitely. Finally, the Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 2.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the proposed FAC-011-4 R7 is both too prescriptive and belongs in a TOP standard and Reliability Coordinator procedures developed under IRO-010. IRO-010 requires the Reliability Coordinator to document the information it needs to perform real-time monitoring, and this level of detail would be better left to that documentation. In addition to RC documentation, BPA believes the drafting team's objective of minimizing burdensome notifications can be achieved through the following proposed edit to TOP-001 R15 (bold, italic text added): **R15.** Each Transmission Operator shall inform its Reliability Coordinator ***of SOL exceedances determined by its Reliability Coordinator's business procedures to merit notification.***	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

ReliabilityFirst offers the following comments on FAC-011-4 for the SDT's consideration. In the clean version of FAC-011-4, in the "New or Modified Term(s) Used in NERC Reliability Standards" section of the Standard, it states: "None." The term "System Operating Limit" has been modified and "System Voltage Limit" is newly defined.

Requirement R6 part 6.1.4, part 6.2.4, and part 6.3 references: "Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." What is the meaning of "that adversely impact the reliability of the Bulk Electric System does not occur?" Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? These parts of Requirement R6 are open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term "… that adversely impact the reliability of the Bulk Electric System."

Requirement R7 does not specify which entities (TOPs? BAs? DPs?, etc.) are to be the receivers of the referenced communications of SOL exceedances. The "timeframe that communications must occur" are left to the discretion of the RC. The Requirement should be revised to clarify which entities the RC must communicate SOL exceedances to, and to specify a timeframe for the communication (of SOL exceedances) to occur.

FAC-011-4 requires the RC to have a SOL methodology and to provide the methodology to other entities (including TOPs within the RC area). TOPs are required (per FAC-014) to establish SOLs consistent with the RC's SOL methodology. The RC's SOL methodology typically specifies that the model to be used covers the entire RC footprint, as well as at least portions of adjacent RC's footprints. TOPs should not be required to follow an RC's SOL methodology to include a model that covers the entire RC (and portions of adjacent RC's) footprint. TOPs don't typically have models this large.

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	

Comment

LES feels that the sub-requirements listed in R7 may cause confusion as they relate to the performance criteria of R6. Suggest changing the word "of" to "based on", which will allow for a distinct correlation between what is and isn't a SOL exceedance. For example, 7.1.4 could be read as an independent check against Facility Ratings, which would raise the question whether it relates to Normal or Emergency Ratings. SOL exceedances should only be declared based on the performance criteria.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	
Comment	

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Likes 0	
Dislikes 0	
Response	

John Allen - City Utilities of Springfield, Missouri - 4

Answer	No
Document Name	
Comment	

Besides the concerns expressed in response to question 1, what is the purpose of communicating SOL exceedances to the Reliability Coordinator? If the purpose is for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then the data specification concept is a more effective and efficient method and should be maintained in IRO-010-2 where each Reliability Coordinator has the flexibility to determine the items that need reported, the method and a timeframe based on their individual operating environment. Having this requirement detached in FAC-011 could lead to misunderstanding of context, expectations and/or compliance failures, which is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distract our operations personnel and doesn't benefit reliability.

R7.2.2. Please explain the rationale for 30 minutes for this one specific item when (according to R6.1 and further explained in the System Operating Limit Definition and Exceedance Clarification whitepaper) pre-contingency exceedances of much shorter timeframes are an indication of unacceptable system performance? This requirement seems to imply the risk of high voltage is minimal for all registered entities and their equipment.

Likes 0	
Dislikes 0	
Response	

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Maurice Paulk - Cleco Corporation - 1,3,5,6

Answer	Yes
Document Name	

Comment

See SEE, EEI and MISO comments

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	Project 2015-09_SOLs Comment_Form-Final.docx

Comment

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT's intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits."

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings; and"

Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true):

FAC-011-4, 7.2.1 "Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and"

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	Yes
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	

Comment

California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance.

In addition, the IRC SRC requests the SDT consider implementing the following clarifications:

Proposed Language (if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings;"

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true):

FAC-011-4, 7.2.1 Post-contingency SOL exceedances of Facility Ratings;

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC’s SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance.

In addition, the IRC SRC requests the SDT consider implementing the following clarifications:

Proposed Language (if our interpretation of the SDT’s intent is correct):

FAC-011-4, 7.1.4 “Facility Ratings ***as described in Part 6.1.1***”

FAC-011-4, 7.2.1 “Facility Ratings ***as described in Part 6.2.1***”

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true by removing the word 'and'):

FAC-011-4, 7.1.4 “Pre-contingency SOL exceedances of Facility Ratings; ***(delete and)***”

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true):

FAC-011-4, 7.2.1 “Post-contingency SOL exceedances of Facility Ratings***;(Delete - and emergency System Voltage limits, and)“***

7.2.2. ***Post-contingency SOL exceedances of*** emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits	
Likes 0	
Dislikes 0	
Response	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL feels the industry needs more time with the implementation schedule to address coordination adjustments between RCs & TOPs to integrate the revisions of the RC's SOL methodology based on the updated framework. This could involve monitoring and system updates for efficient data transfers (automatic logging and reporting) to make these additional reporting requirements manageable for System Operators and Compliance Staff, and of course keeping the compliance records between the TOP and RC in lock-step. The implementation plan document states that the "TOP-001-6" and "IRO-008-3" versions will be retired. IPL believes these are typos (meant to list the older versions of TOP-001-5/IRO-008-2), the SDT will need to revise this document to provide the plan for TOP-001-6 and IRO-008-3.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes, however; this does not fully address Southern Company's specific concerns noted in Question 1 on the requirement revisions related to the establishment of limits, contingency events, and performance framework in FAC-011-4.	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	

Comment
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment
NV Energy supports the following comments provided by EEI: *EEI supports the inclusion of Requirement R7, which provides the industry with a risk -based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.*

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC believes the existing language of R7 may be adequate. However, we think some additional clarity on two specific requirements (R7.1.4 and R7.2.1) would benefit the industry. Both items relate back to how FAC-011-4 Requirement 7 does or does not tie back to the language of Requirement 6. In these two requirements, the clarification requested is, which Facility Ratings are in view as explained below.

New Requirement R7.1.4 states, “Pre-contingency SOL exceedances of Facility Ratings”. Based on our reading of the draft standard, we believe the SDT is referring to the thermal Facility Ratings described in requirement R6.1.1 (i.e. Normal and Emergency Ratings). R6.1.1 reads, “Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.”

Similarly, requirement R7.2.1 reads, “Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits”. We believe the SDT intends for “Facility Ratings” to correspond to the Facility Ratings described in R6.2.1 (“Steady State post-Contingency flow through Facilities are within applicable Emergency Ratings., provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating.”)

Regardless as to whether or not ATC’s interpretation is correct, we believe the industry will benefit in the future from greater clarity. For example, if ATC’s interpretation is correct, the SDT could add wording such as, “Facility Ratings as described in R6.1.1” for R7.1.4 and “Facility Ratings as described in R6.2.1” for R7.2.1.

ATC also has one minor comment on the formatting of R7.1 and R7.2 requirements. The word “and” appears in different sub-requirements, as shown below. We request the SDT review if “and” is correct wording to use, since a reader may interpret that all these items may need to be simultaneously true before the threshold is reached for communicating. The clearest example is R7.2.1. ATC believes that removing “and” and splitting up R7.2.1 as follows may be beneficial:

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and

7.2.2 Post-contingency SOL exceedances of emergency System Voltage limits, and

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	Yes
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

1. The construct in the proposed FAC-0114 (and Requirement R6) maintains how System Operators generally define IROLs today, and the long-standing operating practice where the loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.

The IESO suggests that the footnote to Requirement R6, sub-requirement 6.2.4 be expanded to include this industry practice, as follows:

Sub-requirement R 6.2.4:

“ Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur”[Footnote 1}

[Footnote 1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques. *Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.*

2. The IESO seek clarification as to what is meant by "*expected to produce more severe System impacts*" in R4 Sub-requirement 4.2?

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	

Comment

MEC supports MRO NSRF comments. The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT's intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits."

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 "Facility Ratings as described in Part 6.1.1"

FAC-011-4, 7.2.1 "Facility Ratings as described in Part 6.2.1"

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 "Pre-contingency SOL exceedances of Facility Ratings; and"

Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true):

FAC-011-4, 7.2.1 "Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and"

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes

Document Name	
Comment	
Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following recommendations regarding communication as described in proposed FAC-011-4 Requirement R7.

- Specify to whom the SOL exceedances must be communicated.
- Add language to specify that communication of SOL exceedances includes prevention and mitigation (IRO-008-3 R6) and actions taken to return the System to within limits when a SOL has been exceeded (TOP-001-6 R15). Even if Part 7.1 SOL exceedance is mitigated within timeframes identified for communication of SOL exceedances, this information should be communicated.
- Add language to communicate post-Contingency SOL exceedances of “normal minimum System Voltage Limits” or “normal maximum System Voltage Limits”. An exceedance could occur for an extended amount of time with no communication which may jeopardize the reliability of the System when the next Contingency occurs.
- Specify the time duration for IROL exceedances to be communicated in Part 7.1.1. The NERC Glossary definition states that IROL Tv should not exceed 30 minutes. Texas RE recommends the SDT consider adding language that the RC should communicate IROL exceedances within 30 minutes rather than its discretion.
- Remove “Outages” after “Cascading” in Part 7.1.3 since “Cascading Outages” is not a defined term per the NERC Glossary.

- Capitalize “contingency” in Part 7.1.3 wherever used since it is a defined term in the NERC Glossary. This includes “pre-“ and “post-“ usages.
- Include a description of what “validated risk” in Part 7.1.3 means or when the risk should be validated. The case could exist where there could be “post-contingency SOL exceedances” identified but there is no defined duration (time period) for an RC to “validate” the risk. An RC could take hours to validate that a contingency could occur that violated an Emergency Rating (time duration in minutes perhaps) and not communicate that issue in a timeframe that supports reliable operations (and 7.2 does not alleviate the concern.)

Additionally, Texas RE inquires as to whether a post-contingency operating state is identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation, but it is determined the instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System, would this be required to be identified and communicated since it may not be an SOL exceedance per Part 6.4?

- Use the terms “normal minimum” and “normal high” in Part 7.1.5 to be consistent with the proposed definition of System Voltage Limit.
- Specify a timeframe for the RC to communicate SOL exceedances that are not resolved within 30 minutes in Parts 7.1 and 7.2. If the SOL exceedance is not communicated timely, multiple entities could be working to mitigate the issue and the actions could potentially conflict with each other. Affected entities should be coordinating so they know what is being done and will not affect each other. They should confirm what each is doing to mitigate the SOL exceedance. For example, the RC could be taking certain measures at the same time an LCC is taking different measures. If they are not communicating, this could lead to adverse effects.
- Capitalize “limits” in Part 7.1.2 since it is part of the proposed term System Voltage Limits.

Likes 0	
Dislikes 0	

Response

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	
The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
NIPSCO believes the Implementation Plan Effective Date is short and should be increased from twelve (12) calendar months to **thirty-six (36) calendar months.** We will work with the **EMS** vendor to create a process for related logging. In addition to developing new processes, related **training** will need to be developed and delivered. Furthermore, MISO will develop and implement new **methodology** and protocols. **This will all require additional time.**	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	

Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

The changes to these standards place a considerable reporting requirement on SOL exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal 12 months implementation period to work out SOL reporting methodology with the RC.

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

“These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments”.

Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project.

1. Extend the implementation timeframe - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations.

Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months.

For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

2. Coordinate common SOLs - The MRO NSRF respectfully requests the SDT to consider coordination of all common SOLs similar to what is proposed in **FAC-011-4, Part 3.5** which requires the SOL methodology to define the method for determining common System Voltage Limits between the RC and its TOPs, between adjacent TOPs, and between adjacent RCs within an interconnection.

3. Replace IROL language with "Adverse Reliability Impact" - The MRO NSRF respectfully requests the SDT replace language excerpted from the current IROL definition with the current definition of "Adverse Reliablity Impact" to indicate that no amount of instability, Cascading or uncontrolled separation is acceptable:

Proposed Language

FAC-011-4, Parts 6.1.4 and 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur.

Footnote 1, page 5: Stability evaluations and assessments of instability, Cascading, and uncontrolled separation Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation Adverse Reliability Impacts

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	
Document Name	

Comment

R4.6: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale.

R4.7: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale. Consider adding "for post-contingency mitigation" are not allowed....

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro agrees with the proposed FAC-011-4 R6 provides clarity on SOL exceedances that may alleviate the need for a glossary definition and offers the following comments and suggestions:

FAC-011-4 R6.2.1

The addition of “Steady state-post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating” to “Steady State post-Contingency flow through Facilities within applicable Emergency Ratings” in Requirement 6.2.1 appears redundant and can possibly create confusion.

Please consider the following wording:

“Steady state-post-Contingency flow through a Facility must not be above the Facility’s highest *applicable* Emergency Rating”

Rationale for “applicable” is to reflect that Emergency Ratings must also observe the time duration requirement in the RC’s SOL Methodology, and also that the highest Emergency rating can change seasonally.

The currently proposed language in requirements R6.2.1 and R6.2.2 appears to imply a more nuanced post-contingency performance requirement for flow vs. voltage. As requirements R6.2.1 and R6.2.2 are conceptually the same, so BC Hydro suggest that the use of similar wording.

FAC-011-3 R3.4 “Identify the lowest allowable System Voltage Limit”

If RC is required to identify a specific low voltage limit across its entire RC area, this will likely be a theoretical limit, which may not address the reliability issues that exist in specific areas of the RC Area. Rather than prescribing a specific limit applicable across the system, a list of qualitative considerations for establishing voltage stability based SOLs could be included instead. These considerations may include under voltage load shedding schemes design, voltage instability, loss of synchronism etc), and other prescriptions in support of accurate modeling of post contingency powerflow (e.g. low voltage limit not lower than value that could cause load trip due to process controls or motor contactors dropping etc.).

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments. Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project.months that this may impact our Final Ballot of the Standards within this Project.

1. Extend the implementation timeframe - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations.

Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic

and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months.

For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	

In addition to the specific concerns noted in Question 1, Southern Company offers the following comments on the SOL exceedance determination, use, and communications in FAC-011-4:

1) Requirement 6.4 of FAC-011-4 should have additional clarity that the limitation on manual load shedding only refers to firm load consistent with FERC Order 693. Specifically, the following changes should be made

6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual **FIRM** load shedding is acceptable only after all other available System adjustments have been made.

2) Additionally, the SOL whitepaper, of which the implementation of FAC-011-4 is largely based, appears to mistakenly refer to TOP-001-3 instead of TOP-001-6 on page 6

3) Lastly, the NERC timehorizon and the SOL whitepaper should add an additional time horizon of "Day-Ahead Operations" that can be used to clearly delineate the horizon in which SOLs are established and applicable in FAC-011-4. Ideally, Operations Planning horizon would be slightly modified to prevent overlap, but as this may impact other standards, it would be acceptable to leave more broad if necessary. Specifically, the new horizon would be termed "Day-Ahead Operations – operating and resource plans within the day-ahead timeframe" and replace the Operations Planning Horizon applicability of R5 through R9.

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	
Document Name	
Comment	

OGE supports MRO-NSRF's recommendation to extend the timeframe for implementation from 12 to 24 calendar months.

Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC supports the changes proposed for the FAC-011, FAC-014, IRO-008 and TOP-001 standards. However, the 12 month implementation timeframe should be extended to 30 months. This additional time is needed to allow for the following sequential actions: First, the RC will need to update its methodology (in the case of MISO, this will be through a stakeholder process). Second, the TOP will need to update its operating practices and procedures to follow the revised RC methodology. Finally, likely in parallel, the RC and TOP will need train staff to adhere to the new requirements and methodology and create new processes to ensure documentation is developed, either automatically or manually, as new SOL exceedances are managed as evidence of compliance.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
Some industry stakeholders believe the implementation plan should be 18 months as opposed to 12 months.	

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	
Document Name	

Comment

R4.2 A portion of the redline language, "*applicable to the establishment of stability limits*" is redundant to the language that starts the requirement. The existing language "*to meet the criteria specified in Part 4.1*" already addresses the "that are expected to produce more severe System impacts". Only focusing on "*its portion of the BES*" could permit an RC or TOP to ignore addressing impacts to their neighboring TOP/RC, and as such should be expanded or dropped.

Given the intent is to indicate that not all the contingencies captured within R5 are applicable and/or required in order to establish stability limits, the following suggested language mirrors similar clarifying contingency language proposed by the SDT for FAC-011-4 R6.3:

Proposed Language: *Require that stability limits are established to meet the criteria specified in Part 4.1 for applicable Contingencies identified in Requirement R5.*

R6.2.4 Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

Given that 6.2.4 is applicable only to System performance *following contingencies*, suggest that "does not" be replace with "would not".

· **Proposed Language:** *Instability, Cascading or uncontrolled separation that adversely impact the reliability of the BES would not occur.*

R7 The proposed language in R7 does not solely provide, as the rationale states, "a performance framework for determining SOL exceedances in the RC's SOL methodology." Rather, it provided a communication framework around those SOL exceedances deemed reportable. However, R7 does not indicate any requirement around the communication (from whom & to whom) beyond it being directed to take place by the RC's methodology, which could include an RC communicating internally to itself. The proposed language below proscribes a direction of communication. If the SDT would prefer the RC's methodology to spell out the communication path, then that need should be included in a sub-requirement of R7.

· **Proposed Language:** *Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining which SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated by the Transmission Operator or the Reliability Coordinator to impacted Transmission Operators or Reliability Coordinators, and if so, the timeframe that communications must occur. The approach shall include:*

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following additional comments for proposed FAC-011-4:

- Stability is a defined term in the NERC Glossary, but is used throughout FAC-011 (e.g. stability limits, stability performance, steady-state voltage stability, angular stability) and is not capitalized. Texas RE recommends the SDT take steps to incorporate the defined term into the Standards, update the definition, or retire the definition as appropriate.
- The language of Requirement R2 could imply that the RC owns Facilities, which is not typical.
- Texas RE recommends revising Requirement R2 to match the language in the rationale. It should be revised to "…such that the Transmission Operator**s** and **their** Reliability Coordinator**(s)** use common Facility Ratings."
- Requirement R3.1 shows System Voltage Limit(s) as both singular and plural. Please review for correct grammar.
- Texas RE recommends including a minimum bar for stability performance criteria in Requirement R4. As written, the RC has unlimited discretion to determine performance criteria that is used to establish stability limits, which can lead to action not being taken unless there is an Emergency.
- Texas RE is concerned with the vague language in Part 4.2. The current language indicates an entity will be expected to clearly demonstrate how stability limits are "expected" to produce more "severe" System impacts, but there is no threshold provided for what "severe" is. This language could result in an entity indicating all impacts are the same and there are no stability limits needed.
- In Part 4.3, Texas RE recommends the SDT consider adding "or other Reliability Coordinators Areas within its Interconnection" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections. Part 4.5 is similar: "other Reliability Coordinator Areas within its Interconnection."
- Part 5.3 only requires the RC to "[d]escribe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits." Texas RE recommends including language within FAC-011 or FAC-014 to require the RC to provide justification when Contingency events provided per FAC-014-3 R7 are not used in determining stability limits.
- Texas RE noticed there is no discussion of thermal limits in FAC-011. Does the SDT agree that thermal Facility Ratings are thermal SOLs?

Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	

Comment	
Requirement 6 lists language stating “that adversely impact the reliability of the BES” without detailing what is considered “adverse impact.” This introduces inconsistences among the industry.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
AZPS does not consider the intent of R4.2 to be clear. The language “more servere” is broad and open to interpretation. AZPZ requests that the STD add additional clarifying language to R4.2. R4.2 Required that stability limits are established to meet the criteria specified in Part 4.1 for the contingencies identified in requirement R5 applicable to the establishment of stability limits that are expected to produce more severe system impacts on its portion of the BES. Additionally, AZPS supports the comments submitted by EEI regarding the need to extend the implementation dates for Requirements FAC-011-4 and TOP-001-6. AZPS agrees that entities will see an addition in workload to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-001-6. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. While many entities may already utilize these tools to track exceedances, most will have to further enhance those tools if they are using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most of the EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations. To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	

The addition of R4.7 in FAC-011-4 will have an impact on interconnection with lower system inertia such as the Québec Interconnection.

Because of its unique characteristics (main generation centers located in the north, remote from the main load centers in the south), The QI has no potential viable BES Island in underfrequency conditions. Therefore, the use of the UFLS Program does not relate to system separation.

The Quebec Variance in the NERC Standard PRC-006-3 reflects that situation.

As mentioned in the rationale box for PRC-006-3 requirement D.A.3, the UFLS Program is part of the Hydro-Québec TransÉnergie defense plan to cover extreme contingencies along with two other RAS. Therefore, taking into account the reality of the QI, the use of the UFLS Program would relate more to R4.6 rather than R4.7.

We respectfully request the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6, and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate, and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, we are requesting the SDT consider extending the implementation timeframe to at least 24 months.

We would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which type of owner-provided Facility Ratings are to be used...’.

The definition of SOL includes thermal, voltage, stability, and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

The changes to this standard would place a considerable reporting requirement on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to work out SOL reporting methodology should be extended to at least 24 months. Additionally, the changes to this standard places the obligation ont the Reliability Coordinator to communicate SOL exceedance; however, if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could potentially become an administrative compliance exercise that distracts Real Time Operations

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 3.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy supports the following comments provided by EEI:

As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.

Likes 0	

Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

Requirement R3.5 implies that adjacent Transmission Operators need to have common System Voltage Limits. While theoretically this might seem appropriate, it should be up to the adjacent Transmission Operators to determine acceptable System Voltage Limits for their systems. The voltage limits of adjacent Transmission Operators don't necessarily need to be common, however ITC agrees that Reliability Coordinators should be utilizing the same System Voltage Limits as the Transmission Operators. We also believe that adjacent Transmission Operators should coordinate their individual System Voltage Limits rather than requiring common System Voltage Limits. The intent of the requirement should be reflected in the language.

Another option would be to modify Requirement R3.5 to say:

"Define the method for ensuring that System Voltage Limits are coordinated between Reliability Coordinators and Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection."

Requirement R5 seems to imply that all single contingency events listed in Requirement R5.1.1 should be included in the set of contingency events for use in determining stability limits. However Requirement R4.2 indicates that stability limits are established for only the contingencies that are expected to produce more severe system impacts. Requirement R4.2 is more appropriate as it would be unduly burdensome to expect that stability simulations be performed for all of the contingencies listed in Requirement R5.1.1. Requirement R5 should be split to make it clear that only the contingencies that are expected to produce more severe system impacts need to be considered for determining stability limits while all single contingencies (identified in Requirement R5.1.1) should be considered when perfomring Operational Planning Analysis and Real-time Assessments.

Implementation of these modifications to the standards will require collaboration between some Reliability Coordinators and their respective Transmission Operators to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. The implementation timeframe should be extended to at least 24 months in order to provide more time to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production.

Likes 0	
Dislikes 0	

Response

Robert Hirchak - Cleco Corporation - 6	
Answer	
Document Name	
Comment	
Implementation plan of 12 months is too short to develop operator tools to track.See MISO and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	

Dislikes 0	

Response

Lee Maurer - Oncor Electric Delivery - 1

Answer	
Document Name	

Comment

Oncor supports EEI comments.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which ***type of*** owner-provided Facility Ratings are to be used…’.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a ***type*** of contingency for…'.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ' which type of owner-provided Facility Ratings are to be used…'.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don't believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a type of contingency for…'.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment	
ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Requirement 6 lists language stating "that adversely impact the reliability of the BES" without detailing what is considered "adverse impact." This introduces inconsistences among the industry.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	

Support MRO-NSRF comments for:

1. Extend the implementation timeframe

2. Coordinate common SOLs

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Certainly in FAC-011-4 Requirement R6, but also in the proposed PRC-023-5, CIP-014-3, and FAC-014-3, the pairing of "expected to result in instances of instability, Cascading, or uncontrolled separation" with "that adversely impacts the reliability of the Bulk Electric System" is unnecessarily redundant given that the Glossary of Terms definition of Adverse Reliability Impact is frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. It is not clear if the SDT intends for this language to mean anything other than "expected to result in instances of instability, Cascading, or uncontrolled separation." Additionally, the SDT is perpetuating the industry-wide ambiguity of the term "widespread" by invoking the reference (without capitalization) to "adversely impacts the reliability." A simple, logical change is to simply retain "expected to result in instances of instability, Cascading, or uncontrolled separation" and stop there

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	
Document Name	

Comment

PG&E has no additional comments

Likes 0	
Dislikes 0	

Response

Marco Rios - Pacific Gas and Electric Company - 1

Answer	
Document Name	

Comment

PG&E has no additional comments.

Likes 0	
Dislikes 0	

Response

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3

Answer	No
Document Name	

Comment

FAC-015 seems as an attempt to provide for the PC to TP heirarchy that should exist. However, it appears that there is a lack of coordination between FAC-011, FAC-014, and FAC-015. The goal should be to keep establishment of the Operating and Planning Horizon planning assessment with the closest entity (i.e. the Transmission Planner) and have the results go up the chain (subject to review and approval) from the TP to the PC to the RC and down to the TOP.

The existing combination appears to include would that will not be used and is therefore wasting time and not accomplishing reliability.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA agrees with removing the redundancy of the proposed FAC-015-1 and part of the shift of those requirements to the revised FAC-014-3. However, the proposed FAC-014-3 Requirement R6 remains redundant to existing obligations of MOD-032-1 and TPL-001-4 (soon -5) Requirement R1. The proposed Requirement R6 establishes a significant Compliance risk to planning entities who seek to plan the future transmission System for expansion and load growth, and ignores that Facility Ratings of the moment may not exist in the future planned System. In the proposed Requirement R7, it is unclear what reliability objective is accomplished that is not redundant to the existing IRO-017-1 Requirements R3 and R4. Furthermore, if there is a need to modify TPL-001-4 (soon -5) Requirement R8 to address annual Planning Assessment distribution, it should be revised there. Finally, to reiterate the comment above, FAC-014-3 Requirement R8 is not clear about requiring Planning Coordinators to communicate that "big-3" impacts during a particular planning event (e.g. see Cascading during simulation of a P6 event) were ***observed*** versus that "big-3" impacts ***caused*** a failure to meet System performance requirements. Here, the SDT is making a different interpretation than most planning entities make regarding TPL-001-4 (soon -5). It is not simply that "big-3" impacts were observed; it is that the "big-3" impact required a Corrective Action Plan (CAP) because the Contingency caused a failure to meet System performance requirements of Table 1. In other words, for a P6 event that yields Cascading, the Table 1 performance requirements may allow shedding Non-Consequential Load as part of the allowable mitigations such that System performance requirements are met (and no CAP). WAPA requests that the SDT reconsider the incorporation of the planning entity requirements into FAC-014-3 and, if retained, clearly state the intended reliability objective to retaining them there.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	

Comment	
Understand the good-faith intent of the SDT, but fundamentally the proposed requirements are TPL 001 based (and perhaps even FAC 008 based) and should be placed in the applicable standard if deemed acceptable. The draft standard appears to mandate the Facility Ratings, System steady-state voltage limits and stability criteria to be used by the PC/TP, as set by the RC/TOP methodology. It would probably be more effective to rewrite the drafted FAC-014 standard for the RC's/TOP's to provide their associated technical rationales (beyond a methodology) for the defined operating limits to the PC/TP for input into the TPL assessments. In general, having standards placing requirements for other standards (as a standards setting practice) risks creating confusion. Also support the MRO-NSRF comments. .	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	No
Document Name	
Comment	

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

CAISO believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. Keeping “like” requirements together in one standard will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid undue regulatory burden and support the efforts of the Standards Efficiency Review project. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn without adding Requirements R6 to R8 in FAC-014-3. Accordingly, we recommend:

- Requirements R6 to R8 be removed from FAC-014-3
- The phrase “ and that Planning Assessment performance criteria is coordinated with these methodologies.” be removed from the Purpose (Section 3) of FAC-014-3
- The Planning Coordinator and the Transmission Planner be removed from the Applicablity Section.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Applicable Facility Ratings Duration Criteria was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2), whose purpose is "To establish consistent modeling data requirements and reporting procedures [for each Transmission Owner, Transmission Service Provider, Generation owner, Resources Planner, and Balancing Authority]. TPL-001-4, R1 requires each Planning Coordinator and Transmission Planner to maintain models that use data consistent with that provided in accordance with the MOD-032 Standard that represent projected System conditions. TPL-001-5 further requires that Applicable Facility Ratings shall not be exceeded and that system adjustments are allowed to mitigate rating exceedances if such adjustments are executable within the time duration applicable to the Facility Ratings. If the SDT believes additional detail, such as a criteria regarding which of the Facility Ratings (30 min, 4 hour, continuous, etc.) are applicable under normal and emergency conditions is required, we suggest TPL-001-4 be updated to include those details/criteria so that all related requirements are located together. TPL 001-5 also requires the Planning Coordinator and Transmission Planner to establish system steady state voltages, post-Contingency voltage deviation and transient voltage response. Instead of making the RC's SOL methodology, which is typically developed entirely from the operations perspective without involvement of the PC(s) and TPs, binding on PCs and TPs, TPL-001-5 can be modified so that the RC is a party in the development of the criteria, possibly through a process that is led by Regional Reliability Organizations such as WECC.

As we noted above, keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

In addition, reading the proposed Requirement 6.2 of FAC-011-4, it doesn't appear that there is a material risk for the PC and TP to use less restrictive criteria than the RC that makes including Requirement R6 in FAC-014-3 necessary.[1]

[1] The system performance standards FAC-011-4 requires the RC to include in its SOL methodology are:

Ø System performance for no contingencies demonstrates flows and voltages are within normal ratings but emergency limits may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

Ø System performance for single contingencies demonstrates flow through facilities and voltages are within applicable Emergency Ratings and System Voltgae Limits. Steady steate post-Contingency flow through a facility must not be above the Facilitiy's highest Emergency Rating.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to either: (1) actually include the desired criteria, including the Applicable Facility Ratings Duration Criteria, in FAC-014-3 possibly using similar language as used in Requirement R6 of FAC-011-4 while maintaining consistency with the requirements in TPL-001-5 mentioned above, rather than leaving it to the RC's SOL methodology, or (2) to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings criteria, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

If on the other hand it can be assumed that the SDT is referring to Applicable Facility Ratings Duration Criteria rather than individual Facility Ratings, System voltage limits rather than Facility specific voltage limits and system stability limits then the provision of technical rationale be limited to the Regional Reliability Organization (RRO) as part of the established compliance monitoring process rather than to multiple entities to avoid putting additional regulatory burden on PCs and TPs.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 or Requirement R8 of TPL-001-5 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion, avoid undue regulatory burden, and support the efforts of the Standards Efficiency Review project.

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R3 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 or TPL-001-5, R8 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid placing undue regulatory burden on entities and support the efforts of the Standards Efficiency Review project. We strongly oppose the requirement to inform multiple entities including generator owners because, that could take planning engineers away from their core job. The existing FAC-014 limits such communication to the affected RC. We recommend that arrangement remain unchanged.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

With respect to Requirement R6, ERCOT believes the language contained in the prior draft of FAC-015 should be utilized. The current draft of FAC-014 seems to suggest that responsible entities must provide a technical rationale to each Transmission Planner, Transmission Operator, and Reliability Coordinator in the event of the utilization of a higher rating than was provided for an upgraded circuit. Accordingly, ERCOT suggests replacing the proposed language of Requirement R6 with the language previously utilized in Requirements R1, R2, and R3 of FAC-015.

With respect to Requirement R8, ERCOT believes the Planning Coordinator (PC) and Transmission Planner should communicate only the limited information each Transmission Owner and Generator Owner (GO) needs to know, not necessarily the full details regarding the nature of the instability, Cascading, or uncontrolled separation. ERCOT suggest the use of the following language in Requirement R8:

Each Planning Coordinator and each Transmission Planner shall provide an annual communication to Transmission Owners and Generation Owners that own Facilities that meet the following conditions:

1. The Facility is part of a planning event contingency that the Planning Coordinator or Transmission Planner has identified in its annual Planning Assessment would cause instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the BES if a limit is exceeded; or

2. The Facility is part of a contingency associated with an established IROL or stability limit, which was provided to the Planning Coordinator or Transmission Planner under Requirement R5, Part 5.2.4.

ERCOT also suggests modifying the standards that utilize such information, which are part of this ballot/comment period, to include “Facilities identified in FAC-014” or “FAC-014-3, Requirement R8” as appropriate so that the facilities that must meet those requirements include part 2 suggested above.

ERCOT further notes that it intends to vote in favor of FAC-014-3, provided the foregoing suggested modifications are incorporated.

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the ***(delete - criteria for)*** Facility Ratings, System ***steady-state*** Voltage Limits and stability ***criteria*** as ***determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).***

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

· The Planning Coordinator may use less limiting Facility Ratings ***as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon***, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Lee Maurer - Oncor Electric Delivery - 1

Answer	No
Document Name	

Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment

FAC-014-3 R6

The SPP Standards Review Group asks the SDTs consideration that coverage of FAC-014-3 is included in the data provided in MOD-032-1, and in the model building in TPL-001-4 R1, where the models contain Facility Ratings, System steady-state voltage limits, and stability criteria that are equally limiting or more limiting than the ones utilized by the Reliability Coordinator (RC).

The SPP Standards Review Group asks the SDTs consideration of these differences in the scope for TPL-001-4 R1.

The development of Facility Ratings is the responsibility of the Transmission Owner (TO) in accordance with FAC-008-3. To allow the Planning Coordinator (PC) or Transmission Planner (TP) to develop a “less limiting”, “higher” Facility Rating, could lead to unrealistic and/or invalid Planning Assessments.

The PC and/or the TP should not have the ability to overrule the TOs capability to maintain conservative Facility Ratings in accordance with manufacturer recommendations to protect its personnel and equipment.

If the PCs and TPs want to adjust system models with a higher Facility Rating based on a proposed system upgrade, that is included in TPL-001-4 R1, Part 1.1.3.

FAC-014-3 R6, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

FAC-014-3 R7

The SPP Standards Review Group asks the SDTs consideration that TPL-001-4 R8 is for the PC and TP to share information on their annual Planning Assessments.

The SPP Standards Review Group recommends that the list of entities in TPL-001-4 R8 include RCs and TOPs the ability to request and receive the information.

FAC-014-3 R7, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

FAC-014-3 R8

The SPP Standards Review Group considers existing coverage of FAC-014-3 R8 in TPL-001-4 R8.

The SPP Standards Review Group recommends that the list of entities in FAC-014-3 R8 include TOs and Generator Owners (GOs) the ability to request and receive the information.

FAC-014-3 R8, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

The proposed requirements R7 and R8 in FAC-014-3 are unnecessary. Requirement R5 ensures that the Reliability Coordinators provide the Plannning Coordinators and Transmission Planners the SOLs for their respective areas. If instability is identified in the Planning Assessments which drives an SOL, it would be provided to the TOPs through instabilitie identified by requirement R5. If the identified instability does not require an SOL then providing that information to TOPs could lead to uncertantity as to what to do with the information. Many of the instabilities identified by Planning should be items strictly for the Planning Horizon, as Planning should be addressing them with Corrective Action Plans prior to them making it to become a Real Time Operating Horizon SOL issue.

FAC-014 Requirement R6 is more appropriately placed in the TPL-001 standard to avoid possible confusion in completing the task in finalizing the completion of the models needed for performing the Near Term Assessments. All of the other requirements for the models are identified in this standard.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI is supportive of the general concepts for Requirements R6 through R8, the language lacks sufficient clarity to address what results or outcomes are expected. Given this ambiguity, the outcomes could result in inconsistent application across the various regions. Moreover, the current language in these three requirements do not adequately conform to the tenant of a Results Based Standard. For these reasons, we cannot support the currently proposed draft of FAC-014-3 at this time.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 “Establish and Communicate System Operating Limits” should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.

Southern Company also suggests a modification to R7 of the proposed FAC-014-3 that will help focus the communication of any instabilities identified in the Planning Assessment to include only those contingency events which are the most impactful, as follows:

R7 Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the near-Term Transmission Planning Horiozon, ***using planning event contingencies only****, to each impacted Reliability Coordinator.*

FAC – 014 R7 and R8 could result in burdensome communication even if there isn’t any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

Modify the last sentence of FAC-014 R7 from “This communication shall include:” to “This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:”

Modify the first sentence of FAC-014 R8 from “shall annually communicate any instability…” to “shall annually communicate if there is any identified instability…….”

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	No
Document Name	

Comment

FAC-014-3 Requirements (R6 – R8) are not well aligned for inclusion in a FAC Standard and there are already similar requirements in TPL-001-4. Requirement R8 in FAC-014-3, which requires annual communication of any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment, appears to already be covered by requirement R8 in TPL-001-4. In addition, FAC-014-3 Requirements (R6 - R8) are only related to the Near-Term Transmission Planning Time Horizon. There appears to be a need for further clarification regarding the relevant Time Horizon(s) which reference: "Time Horizon: Long-term Planning."

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy does not agree with the proposed requirement R6 of FAC-014-3. The proposed requirement requires additional clarity on the potential opportunity of a RC creating a Facility Rating based upon its own SOL methodology, and removing the ownership provided to Entities through FAC-008-3. FAC-014-3 requirement R6, currently reads that each Planning Coordinator and Transmission Planner shall implement a process to use Facility Ratings…that are equally limiting or more limiting than the criteria for Facility Ratings…as described in its RC's SOL methodology. NV Energy currently interprets this this as the RC can create a Facility Rating based on its own SOL methodology. Under this interpretation of the requirement, NV Energy cannot approve the current draft of the requirement R6..

Additionally, the remainder of the Standard, FAC-014-3, states that the PC and TP may use less limiting Facility Ratings, if the Entity provides a technical rationale. NV Energy interprets the intention of this language that the TP can use a less limiting element (higher facility rating) than what the RC provides, but that isn't entirely clear in the requirement's current draft.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 4.

Evergy would further respond:

Proposed Revisions Add Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to use "less limiting" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The proposed Requirements R6-R8 in FAC-014-3 all require actions associated with the PC and TP annual Planning Assessment, which is required by TPL-001. If not already sufficiently addressed by the Requirements in TPL-001, we believe it would be better to address any additional actions associated with the annual Planning Assessment in a revision to TPL-001 to avoid requirement fragmentation between TPL-001 and FAC-014.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The proposed FAC-014-3 Requirements R6 through R8 obligate the Planning Coordinator and Transmission Planner to share information on their annual Transmission Planning Assessments. The proposed requirements are redundant because Planning Coordinators and Transmission Planners are already required to share planning assessments under TPL-001-4, Requirement R8. Requirement R8 states: "**Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.**" The proposed requirements would be inefficient, increase administrative compliance responsibilities, and would be contrary to ongoing work of the NERC Standards Efficiency Review project. Alternatively, if the SDT does not withdraw Requirements R6 through R8, the intent with regard to the Time Horizon must be clarified. SOLs applied to support the Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. Stability limits identified by the Reliability Coordinator may become invalid in the Planning Time Horizon as new generation is potentially added in future power flow models. When this occurs, it is the Transmission Planner's and Planning Coordinator's stability limits that must be communicated to the Reliability Coordinator so that the Reliability Coordinator knows what to expect. Also, the two bulleted items in the newly proposed Requirement R6 are troubling. The development of Facility Ratings is the responsibility of the Transmission Owner, per FAC-008. To allow the Planning Coordinator and Transmission Planner to develop a "less limiting" Facility Rating could result in inaccurate Operational and Transmission Planning Assessments. The Planning Coordinator or Transmission Planner should not be allowed to independently overrule the Transmission Owner's responsibility to develop Facility Ratings.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA agrees with the withdrawal of FAC-015-1 and consolidating the requirements into FAC-014-3. However, BPA offers the following comments on the new Requirements.

FAC-014-3 Requirement R6: Facility Ratings are modeling data, as developed and reported in Standards FAC-008 and MOD-032. System steady-state voltage limits and stability criteria used in Planning Assessments are criteria developed and documented in annual system assessments required by Standard TPL-001.

BPA suggests including the following language (bold. italic text added) to add clarity to R6:

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that, when developing its steady-state modeling data requirements, Facility Ratings used in its Planning Assessment*** of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for Facility Ratings described in its respective Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for System steady state voltage limits and stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology.***

FAC-014-3 Requirement 7: BPA believes it should only be necessary to communicate information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. This is also consistent with the SDT's response to comments from the previous posting.

BPA suggests including the following language (bold, italic text added) to add clarity to R7.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No

Document Name	
Comment	

OGE supports the concerns expressed by MRO-NSRF on the proposed FAC-014 R6, R7 and R8. OGE believes that the proposed R6, R7 and R8 are duplicative of requirements in TPL-001-4.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	
Comment	

While the intent of the requirements in FAC-014 does not appear to be reflected in the actual words. These requirements are confusing and create ambiguity that could result in incomsistent results, especially with auditors.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	
Comment	

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment
MEC supports MRO NSRF comments. **R6 Concerns** The NSRF does not support incorporating R6 into FAC-014 for the following reasons: *Duplicative*. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions.*" *Questions for SDT Consideration* 1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC? 2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope. *Adds Reliability Risk.* Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether. The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment. We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*). **R7 Concerns** The NSRF does not support incorporating R7 into FAC-014 for the following reasons: *Duplicative*. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment. *Recommendation*. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7. **R8 Concerns** The NSRF does not support incorporating R8 into FAC-014 for the following reasons: *Duplicative*. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment. *Recommendation*. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy recommends that FAC-014-3 R7 be modified to include the phrase "during the planning events" as an added measure of clarity. For example: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified "during the planning events" in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator.

Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.

Likes 0	

Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP disagrees with incorporating R6-R8 into FAC-014 as currently proposed. It is not clear exactly what the SDT believes the benefits would be of such an approach. FAC-014 and its obligations have historically been centric to the Operations Planning Time Horizon, not the Near/Long Term Planning Horizon as currently proposed in these most recent revisions. To do so would change the original intent and purpose of FAC-014 into something more reminiscent of TPL-001. We believe the SDT needs to clarify their strategies and intentions regarding the "mixing" of these time horizons, and for them to further consider the unintentional impacts of making such changes. The "planning assessments" proposed in FAC-014 seem redundant to that which is already required under TPL-001. We believe the SDT needs to be clear as to the intent of R6-R8 with regard to the Time Horizon. SOLs applied to support Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. If the intent is to ensure SOLs applied in the Operations Planning Time Horizon are incorporated in any Planning Assessments performed, the existing language does not accomplish this. An RC's stability limits may become obsolete and thus inapplicable in the planning time horizon as new generation is added. When this happens, it is rather the TP's and PC's stability limits that ought to be communicated to the RC so the RC knows what to expect in the future. If industry and the SDT believe that the obligations proposed in R6-R8 are indeed worth pursuing, it may be worth considering including them within a new FAC standard of their own.

The revised FAC-014 R6, R7, and R8 apply directly to the conduct and communication of planning assessments. While we recognize that TPL-001 is not within scope of the project's SAR, we believe such obligations are already captured as part of TPL-001.

FAC-014 R6 states "Each Planning Coordinator and each Transmission Planner shall implement a documented process", but it is not clear exactly where the creation of this documented process is/was originally required.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions*."

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

R6. This requirement is out of place in FAC-014 and should already be covered in the data provided via MOD-032-1 and model building effort via TPL-001-4 R1, which specifies that models "*shall represent projected System conditions*". Therefore, why wouldn't the models already contain Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the Reliability Coordinator? If there are significant differences between how the system is being planned and how it's being operated, then that should be within the scope for auditing TPL-001-4 R1 today. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project.

Additionally, the two bulleted items are problematic since the development of Facility Ratings is the responsibility of the Transmission Owner in accordance with FAC-008. To allow the Planning Coordinator or Transmission Planner to develop a "*less limiting*" (higher) Facility Rating could lead to unrealistic and/or invalid Planning Assessments. The Planning Coordinator and/or Transmission Planner should not be allowed on their own to overrule the Transmission Owner's ability to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment. However, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, then that is already allowed via TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. Therefore, the list of entities in TPL-001-4 R8 should be enhanced to allow Reliabilty Coordinators and Transmission Operators the ability to request and receive this information.

R8. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. It also appears in the rationale document for FAC-014 the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners. Therefore, the list of entities in TPL-001-4 R8 should be expanded to allow Transmission Owners and Generator Owners the ability to request and receive this information.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification

which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.	
Likes 0	
Dislikes 0	
Response	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes

Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion we need to be careful that there is only one methodology for SOL's going forward. We agree with the proposed requirements but also suggests that the team consider instead adding these requirements within TPL-001, which deals with the Planning Assessment and correspondence/communication of the Planning Study to affected entities.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Facility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but us silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	

FAC-014-3 The statement “any instability identified in its Planning Assessment of the Near-Term Transmission…” seems unclear. I think an improvement and more clear statement might be, “any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…”.

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

1. The IESO is concerned that there is no requirement for the affected RC to provide feedback on the technical rationale provided by the PC or TP for using less limiting ratings. The IESO proposes to add a sub-requirement to establish this feedback loop between the affected entities and the PC or TP. The proposed requirement would mirror Requirement R8, sub-requirement 8.1. of Reliability Standard TPL-001-4 which allows the recipient of the Planning Assessment results to provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments:

Proposed Requirement R6, Sub-requirement 6.1:

“The recipient of the technical rationale may provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments”

Alternatively, the IESO would like to clarify if Requirement R8., subrequirement 8.1 is the feedback loop that can be used to address the lack of input from the affected entities on the technical rationale provided by the PC or TP on the use of less limiting ratings (this is based on the assumption that the technical rationale would be part of the Planning Assessment results).

2. Similar with the Reliability Standard TPL-001-4 where an RC can provide input on the Planning Assessment criteria, the IESO believes that the PC and TP should be afforded the reciprocal opportunity to provide input to its RC's methodology and have the RC provide a document response.

The IESO proposes to add *Sub-requirement R9.3 to FAC-011-4 as follows:*

"9.3. If a recipient of the Reliability Coordinator SOL methodology provides documented comments on the methodology, the respective Reliability Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments."

3. We find that Requirements R7 and R8 are duplicative of existing communication requirements within other Reliability Standards. Specifically,

{C}o **Requirement R7 requires the PC and TP to communicate, annually any CAP identified in its Planning Assessments to the RC. Requirement 8 in TPL-001-4 requires the PC and TP to provide its Planning Asssessment results to affected entities, which include any CAP developed in R2 Sub-requirements 2.7 of TPL-001-4; and**

{C}o **Similarly, Requirement R8 requires the PC and TP to communicate, annually , any instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES in its Planning Assessment of the Near- Term Transmission Planning Horizon to TOs and GOs. All Planning Assessments performed by PCs and TPs are governed by other standards (TPL-001, PRC-012, PRC-023 etc.) and the processes required by those standards already include provisions for the communication of those results to the entities that have a reliability need.**

We suggest that Requirements R7 and R8 be removed to avoid duplication with existing communication obligations for the PC and TP.

Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Hirchak - Cleco Corporation - 6

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	
Answer	
Document Name	FAC-014 SBS Comments 8-3-2020.docx
Comment	
Likes 0	
Dislikes 0	
Response	

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	

R3. What is the purpose of the Transmission Operator providing its SOLs to the Reliability Coordinator? If it's for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then keeping this requirement is redundant with the data specification in IRO-010-2 and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Furthermore, by definition SOLs change continuously based on "*a specified system configuration*". Therefore, does the SDT expect the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment? This is another reason why the information/data exchange activity needs to remain within IRO-010-2, where each Reliability Coordinator can determine the items that need reported, the method and a timeframe based on their individual operating environment.

R5.1 and R5.2. If one purpose of Project 2015-09 is to eliminate planning-based SOLs and IROLs, then what is the purpose of the Reliability Coordinator providing them to the Planning Coordinator and Transmission Planners in this requirement? If it's for the purpose of better aligning planning and operations, then where is the requirement for the Planning Coordinator or Transmission Planner to use them in the models for the Planning Assessments? If there isn't a corresponding obligation, then it potentially becomes an administrative compliance exercise that isn't benefiting reliability. Additionally, the model building topic is covered in MOD-032-1 and if the intent is to use additional information identified during operations in the models for TPL-001-4 Planning Assessments, then MOD-032-1 should be enhanced and the Reliability Coordinator should be added to the applicability. Having it dispersed in other standards could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient.

R5.3 and R5.4. What is the purpose of the Reliability Coordinator providing IROL information to the Transmission Operators? If it's for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep these requirements detached in FAC-014 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
It is also important that RC and/or TO provide technical rationale to PC if they are using less restrictive SOLs than PC's SOLs.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

“These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments”.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on “*a specified system configuration*”.

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs’ specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator’s Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

If retained, we believe FAC-014 should be revised as "Each Reliability Coordinator shall establish stability limits to be used in operations when *an instability* impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology."

Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	
Document Name	
Comment	
R5.5: This language is awkward. Please clarify and reword to capture intent.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	

Comment	
Measure M3, the phrase “in accordance with its Reliability Coordinator’s SOL methodology” should be stricken since it is stricken in the requirement. Proposed language “in accordance with requirement R3” would suffice.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	
Document Name	
Comment	

R3 - The new language provides no suggested timeline beyond the Time Horizon of Operations Planning. Many SOLs, the limit itself, not the basis for the limit which can include Facility Ratings, at minimum, are derived/determined in the Real-time horizon. The Rationale gives several options/examples of how this might transpire which are not governed by the requirement language, which drops the suggested option of “*in accordance with its Reliability Coordinators SOL methodology*”. As such, the proposed SDT language for R3 is ambiguous and either allows the TOP to indicate an SOL as they see fit, or continuously.

Yet, the measurement indicates that evidence demonstrating the TOP provided its SOLs in accordance with its RC’s SOL methodology. Which seems appropriate.

R5 - RC’s have Facility Ratings. RC’s have stability limits. RC’s have criteria for the determination of IROLs. The value of the SOL, which could include, for example a single temperature set rating for a given facility, is of minimal benefit to a PC or TP and is an incomplete set.

· The methodology and ratings sets that can lead to potential SOLs would be of value to the PC or TP.

As written, this requirement and many of its subparts serve minimal reliability value and is highly administrative in nature; and is not an improvement over the current FAC-014-2 R5. Requiring the formalized exchange of such information is not necessarily a determination that it is of value to the recipient.

Suggest R5 be rewritten to align with R6 and provided the criteria, methodology and supporting data (including Facility Ratings) that may be both relevant and beneficial to a TP or PC. Alternatively, providing a list of SOL exceedances and/or trends may also be of some value to the PC or TP. A long list of SOLs with no additional context is an overlap of other requirements/obligations set on the TO/GOs in other standards.

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends the SDT consider the following:

- In Requirement R4, add "adjacent Reliability Coordinators Areas **within its Interconnection** or" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections.
- Revise Part 5.4 from "each established stability limit or each IROL" to "each established stability limit **and** each IROL applicable to the impacted Transmission Operator". Both the stability limit and the IROL should be provided to each impacted Transmission Operator.
- In Requirement R6, the term "System steady-state voltage limits" is not defined. Is this term intended to be different than the proposed term "System Voltage Limit," which was introduced in this project?
- Include a check and balance for use of the less limiting parameter in Requirement R6. This requirement allows for any criteria to be used (i.e. less limiting Facility Rating, etc) as it simply states a "technical rationale" has to be provided to any entity affected by a "less limiting" parameter.
- Requirement R6 uses "affected Transmission Planner, Transmission Operator and Reliability Coordinator," while R7 references "impacted Transmission Operator and Reliability Coordinator" and R8 references "impacted Transmission Owner and Generation Owner." Unless there is a specific reason for difference in verbiage, Texas RE recommends being consistent to avoid confusion and potential interpretation attempts at differences in language in the Requirements.
- Requirement R7 appears to exclude any CAP for Cascading or uncontrolled separation. Please provide the rationale for the exclusion.
- Provide more clarity in Requirement R8. In the phrase "any Facilities critical to the instability, Cascading or uncontrolled separation identified," it is not clear what would constitute "Facilities critical to the instability, Cascading or uncontrolled separation identified," and how these are different than "Facilities that comprise the Contingency(ies) (planning events only)."
- Requirement R8 requires the PC and TP to communicate "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified." Many of the updated Standards (e.g. CIP-014-3, FAC-003-5) use the applicability language "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events". It would be helpful if the information provided by the PC and TP directly maps to the applicability section of these other Standards. Texas RE recommends requiring that communication to the TO and GO include "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events" instead of "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified."
- Requirement R8 uses the phrase "planning events only." Texas RE recommends including an explanation that these events refer to the events in Table 1 of TPL-001.

Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
The time horizon in R6-R8 are currently identified as “Long-Term Planning Horizon” While this aligns with the horizon of the TPL-001-4 standard where issues would be identified, it is specifically the Near-Term Planning horizon that these issues point to. We recommend adjusting the time horizon assocoaited with R6-R8 to more accurately reflect the portion of the TPL-001-4 assessment they are intended to align to.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	
NERC Standard IRO-17 obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. NERC TPL-001 includes the obligation that when the analysis indicates the inability of the system to meet the performance requirements. We believe FAC-014-3 R7 basically includes/requires the same if not similar information. If this additional detail is required, we suggest that IRO-017 be updated so that this type of request is located in a single requirement or standard.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy would like to communicate its additional concern over FAC-014-3, with the retirement of FAC-010-3. With the retirement of FAC-10-3, Transmission Planners will not be able to use their IROL methodology for the Planning Horizon anymore, and as stated, will be forced to adjust to their respective RC's SOL Methodology and definition of an IROL. NV Energy's concern with using a respective RC's IROL definition is the potential for the RC to identify an IROL for a more conservative loss than what a Transmission Planner would determine. NV Energy understands the need for a secure BES with the establishment of an IROL in an Interconnection; however, the ramifications of an IROL declaration stretch into multiple Standards that require a substantial amount of work for compliance implementation (i.e. CIP Standard suite), as well as the equipment modifications for facilities to monitor the flows on Elements within an IROL. NV Energy still believes their should still be a responsibility of defining IROLs with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	

No Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	

Comment

The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports the comments filed by the IRC SRC.

The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

The SDT proposal to retire FAC-010 and the requirement to establish SOLs and IROLs for the planning horizon appear to be the result of the following two misconceptions:

- The “new” TPL 001-4 standard eliminates the need for developing SOLs and IROLs for the planning horizon, which is incorrect and
- SOLs are not useful for the reliable planning of the BES, which is also incorrect.

TPL 001-4 standard does not replace the need for developing SOLs and IROLs for the planning horizon and eliminate the need for the existing FAC-010 and Requirement R3 and R4 of the existing FAC-014. This is because TPL-001-4 is all about ensuring reliable service to firm load and firm transmission services. It does not require planning entities to stress tranfers on any part of the system to determine its limit. Also, since TPL-001-4 studies do not require stressing the system they are less suited to identifiying contingencies the lead to system instability, cascading and uncontrolled separation compared to SOL and IROL Studies performed under FAC-014 R3 and R4. Even if, TPL 001-4 studies identify contingencies that lead to such adverse impacts, they would be mitigated, which means there would be no planning contingencies with such adverse impacts.

SOLs are useful in the reliable planning of the system. For example, in the Western Interconnection (accepted) path ratings, which California ISO deems to be SOLs and are typically developed in the planning horizon, are used in the reliable planning of the system. In all its studies including the annual reliability assessment and local capacity studies, the CAISO ensures these SOLs are not exceeded. For example, reliability assessments and local capacity studies performed use this SOL information.

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	
Comment	
Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
No. Thank you	
Likes 0	
Dislikes 0	
Response	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	

Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

Marco Rios - Pacific Gas and Electric Company - 1

Answer	
Document Name	

Comment

PG&E has no additional comments.

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3

Answer	
Document Name	

Comment

These standards appear to be fine.

One general comment on various FAC standards is the use of the term "impacted." It is used as a non-capitalized term however, how is an entity supposed to determine if another entity is impacted or not?

If Clark is suposed to do something or say something to an impacted RC, what criteria is it to use to determine whether RC West is just an RC or an impacted RC?

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	
Document Name	

Comment

PG&E has no additional comments.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

No. Thank you.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	

Comment

Support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response	
Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	

n/a

Likes 0	
Dislikes 0	
Response	

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	

IPL offers no further comment.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy agrees with the requirement language provided for TOP-001-6 R14, but has concerns with the language provided for the measures for R14. NV Energy has concerns with the phrase “successfully mitigated”, and it not being appropriate, even if it is just for suggested evidence. Requirement R14 states only to show a Plan that was initiated to mitigate SOLs, not to prove mitigation. While success is obviously the desired outcome, it is not the only possible outcome, and this language addition to the measures for R14 seems to extend beyond the intent of the requirement.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

None	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments for proposed IRO-008-3:

- In Requirement R1, revise Interconnection Operating Reliability Limits to Interconnection Reliability Operating Limits.
- In Requirement R5, "exceedance" is added after SOL but is not in Requirement R6. It was added in the VSL/VRF matrix for Requirement 5 and parts of Requirement R6. Requirement R6 VSL/VRF only has "exceedance" added within the first statement and not the second statements (after the "OR" in Lower, Moderate, and High VSL columns on page 12 of 15). Since the language appears to be so similar, Texas RE recommends consistency in where exceedance is added.
- Requirement R7, as well as the measure, capitalizes "Real-time Monitoring." Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized.
- Texas RE noticed the Data Retention section does not include Requirement R7. Texas RE recommends Requirement R7's data retention match Measures M1 - M3, Measure M5, and Measure M6 at a minimum.
- Texas RE noticed the Guidelines and Technical Basis has been removed from this standard, but it is still in place for other standards, such as PRC-026. Texas RE recommends following the Technical Rationale Transition Plan and determine whether the Guidelines and Technical Basis is Technical Rationale or Implementation Guidance.

- Texas RE recommends the IRO-008-3 mapping document include the BA since it is included in the standard.
- Texas RE has the following comments for proposed TOP-001-6:
- The term “Real-Time System Operators” is used in several places in the rationale document. Since it is not a defined term in NERC Glossary, Texas RE recommends using the term System Operator, which is defined.
- In Requirement R15, it is unclear as to whether the phrase “in accordance with its Reliability Coordinator’s SOL methodology” is referring to the “exceeded” SOL or the need to “inform”. The VSL/VRF matrix language structure places the phrase after “inform”. Texas RE recommends reviewing the sentence and make clarifying changes as necessary.
- Requirement R25, as well as the measure, capitalizes “Real-time Monitoring”. Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized. It is also capitalized in the VSL/VRF matrix and the Evidence Retention sections of the standard.
- Texas RE requests justification for revising the Evidence Retention requirement for Requirement R14. This justification for the change could be captured in the mapping document for TOP-001-6.
- The mapping document appears to contain guidance on how to comply with TOP-001-6, in the statement “communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output”. This is not a method to inform the RC of “actions taken”. ICCP reflects results of actions but does not necessarily reflect the action(s) actually taken. The mapping document is not an appropriate place for putting guidance on how to comply with the standard and the process for developing Implementation Guidance can be utilized if the SDT would like to provide guidance on complying with the standard.

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
Need to add the word "its" to the modified portion of Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf

Comment

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Considering that "Consistent with SOL methodology" is mentioned throughout the Standard, suggest referencing "SOL expectations outlined in FAC-011-3" somewhere within the Standard.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	
Document Name	

Comment

MEC supports MRO NSRF comments.

RO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	

Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

IRO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

The changes to these standards place a considerable reporting requirement on SOL

exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal

12 months implementation period to work out SOL reporting methodology with the RC.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Why R25 couldn't have just been incorporated into R14? R25 basically stating a TOP has to use its RC's methodology, which indirectly implies it has to be in each TOP operating plan for the identified SOL exceedances for R14?	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	

Document Name	
Comment	

IRO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL/IROL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

IRO-008 R6. What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL/IROL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	
Response	

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?

Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	

Regarding the changes to CIP-014, Seattle City Light has five areas of concern. The first three relate to revised Section 4.1.1.3 and the fourth and fifth address impacts to existing R1.

First, the changes to Section 4.1.1.3 to replace the reference to IROL Facilities identified by an entity's Reliability Coordinator, Planning Coordinator, or Transmission Planner with Facilities associated with instability, Cascading, or uncontrolled separation, that also adversely impact BES reliability for planning events, is inconsistent with Criteria 2.6 of CIP-002 Attachment 1, from which Section 4.1.1.3 was taken. The applicability CIP-014 is designed to conform to the criteria of CIP-002 for Medium impact Transmission Facilities. For consistency among the CIP Standards, Seattle suggests that CIP-002 Attachment 1, Criteria 2.6, also be changed along with CIP-014.

Second, the changes to Section 4.1.1.3 are confusing and perhaps redundant. As proposed, the criteria to identify applicable Facilities has two components: (i) loss that creates instability, Cascading, or uncontrolled separation, (ii) that adversely impacts BES reliability for planning events. So far as Seattle is aware, nowhere else in the NERC Standards are the "big three" bad events (instability, Cascading, uncontrolled separation) qualified in this way; they are presumed by their existence to create adverse BES impacts. In addition, the language "adverse impact for planning events" adds another layer of confusion. What is an adverse impact for a planning event? Considerable effort has been spent by NERC and industry over the years to qualify "adverse BES impact" for CIP-002, yet this new language introduces a different new concept that expands adverse impact to new territory. Additional clarity is required. As a simpler solution, Seattle suggests that the qualifier phrase "that adversely impacts…" be dropped from the proposed change to Section 4.1.1.3.

Third, the changes to Section 4.1.1.3 add a new burden on entities that was not previously present. For IROLs, there exist established processes to inform entities of the existence of IROLs and document those Facilities critical to their derivation. The "IROL Cards" and IROL website used in the Western Interconnection are examples of these processes. As a result, it is easy for entities to apply existing Section 4.1.1.3 criteria (as well as those of CIP-002 Criteria 2.6) and crystal clear to document conclusions at audit. For the proposed changes, there is no established mechanism or consistent process for Planning Coordinators or Transmission Planners to share with entities information about Facilities related to BES instability, Cascading, or uncontrolled separation, nor is there established language about how to identify such Facilities. Presumably such information is shared in some fashion as a matter of good practice, but absent any established means to do so and consistent approach to documentation, the change creates a new burden on entities to track down such information from others and to clarify findings in unequivocal, crystal clear language to satisfy any auditor. As a solution, Seattle suggests that somewhere in the body of changes introduced by Project 2015-09, there be a new requirement for Planning Coordinators and Transmission Planners to inform subject entities, in a standardized manner, of Facilities related to to BES instability, Cascading, or uncontrolled separation.

Fourth, the changes to Section 4.1.1.3 cause redundancy for CIP-014 R1. Specifically, R1 requires a transmission planning study to identify Facilities associated with instability, Cascading, or uncontrolled separation. These are the identical criteria that cause a Facility to be applicable in 4.1.1.3. As proposed, the requirement would require a transmission study on Facilities identified to be associated with instability, Cascading, or uncontrolled separation to determine if they are associated with instability, Cascading, or uncontrolled separation. Ridiculous! As a possible solution, Seattle suggests CIP-014 R1 be rewritten to exempt from evaluation any Facility meeting Section 4.1.1.3 (because it already has been so evaluated), and revise R2 to require a third party evaluation of the entity's R1 study and the Section 4.1.1.3 evaluation of the applicable Planning Coordinator/Transmission Planner.

Fifth, the different qualifiers used in Section 4.1.1.3 and R1 create unnecessary confusion. Section 4.1.1.3 qualifies applicability based on "adversely impacting the reliability of the BES reliability for planning events" whereas R1 qualifies applicability "within an Interconnection." It is not clear how these different qualifiers impact identified instances of identified instability, Cascading, or uncontrolled separation. There's enough confusion and auditor dissent for CIP-014 about how to apply the "within an Interconnection" qualifier; no new confusion is needed. As suggested above, Seattle recommends that the Section 4.1.1.3 "adverse impact" qualifier be removed, which would also address R1 confusion as discussed here. If qualifying language is desired, Seattle recommends that the same language be used in Section 4.1.1.3 and R1.

Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

We agree with the retirement of planning based IROLs. We also agree with the

changes made to the CIP-014 and PRC-023 standards. However we don't agree with the use of a

general statement to say that the retirement of FAC-10 will eliminate all planning based SOLs.

Planing coordinator can still use their SOLs with valid technical rationale.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.

Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	
Comment	

LES supports comments provided by the MRO NSRF related to CIP-014.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment
AEP continues to have concerns regarding 4.2.2, Transmission Facilities, within FAC-003. Proposing new requirements in FAC-014 to ensure a Transmission Planner is performing a "planning assessment" does not automatically ensure such efforts will naturally flow to FAC-003 simply because they are in the same standard family. The SDT may be making some assumptions regarding communication in that regard. It should not be assumed that communication between a Transmission Planning function and a Transmission Owner (a Forestry department, for example) would be a naturally occurring activity. If these changes are indeed pursued, the SDT will need to give consideration on how to ensure this communication is taking place. It should also be noted however that while more insight is needed on ensuring this communication takes place, care should also be taken to ensure no restrictions or limitations be unnecessarily placed on the parties involved. These proposed revisions could unintentionally lead to a line not being properly identified. Any planning event causing instability that is identified in planning assessments, whether the contingency is above or below 200 kV, would have a corrective action plan which may possibly include generation redispatch. If generation redispatch is applied in the operation time-frame, as might be assumed in planning, there is no instability for a planning event and no lines will be identified. We are not certain whether or not the SDT realizes this could be applicable to CAPs of any nature. Could the SDT provide insight as to whether these proposed revisions are requiring that the identification of lines below 200 kV take place pre-CAP or instead post-CAP? In any event, we disagree with the proposed revisions, which we believe changes from identifying lines in a practical way, to doing so in a less practical manner using planning studies. As stated in the previous comment period, we believe additional text is needed here to ensure no lines are unintentionally excluded by a) the timing of their being identified as part of an IROL and b) the timing of any facilities identified, which could lead to instability, Cascading, or uncontrolled separation within associated planning assessments. The SDT's response from the previous comment period gives the impression that they may possibly be unaware of the guidance provided in the original Errata which was eventually incorporated into the GTB. The team provided an example of a line identified as an IROL and then incorporated into FAC-003 and that "it could be months or years before the vegetation management caught up with the designation, providing no practical benefit." The SDT may wish to further review the GTB of this standard to ensure they are aware such guidance has already been provided in this standard regarding how soon after a line is identified that it becomes incorporated into the vegetation management program. With this in mind, AEP once again recommends that this section be clarified in the following manner… *"Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation* ***<u>or overhead transmission line operated below 200kV that have been established as part of an IROL by the Reliability Coordinator per IRO-014-3 R1.</u>****"*   Proposed Implementation Plan: The changes proposed are very expansive and involve many individuals across a number of Functional Entities. In addition, new cross-functional procedures and processes would need to developed and established to meet the proposed obligations. As a result, we believe 36 months would be more appropriate. We believe the references to planning events in CIP-14 Applicability Section 4.1.1.3 and FAC-003 Applicability Sections 4.2.2 and 4.3.1.2 could be more clearly stated. We recommend that CIP-014 Applicability Section 4.1.1.3 be revised to state "Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator, or Transmission Planner, per its Planning Assessment of the NearTerm Transmission Planning Horizon as Facilities that if lost or degraded *due to planning events* are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System." AEP would like to make a suggestion and encouragement regarding how the standards drafting team provides redlined documents for industry review. While redlined documents using the previously proposed revision as a baseline do provide a very beneficial way for the

reader to identify only the most-recently proposed changes, we believe that they cannot be the only redlined document provided during these comment and balloting periods. These particular redlines are simply a "delta" between the current and previous draft revision and do NOT show all the proposed additions and deletions that have been retained-to-date. This could result in the reader misunderstanding or misinterpreting the content in the draft. For example, text shown in black could be a) text currently included in the version under enforcement or b) new text that was proposed in a previous comment period but "no longer considered new text" in the current comment period. In addition, text shown as deleted could be a) text that has been newly proposed for deletion in the current comment period or b) text that was proposed for addition in a previous comment period draft but then later struck from consideration in a latter comment period. As a result, when multiple revisions are proposed over time, the reader would have to review each and every draft proposed to date and somehow determine for themselves all the changes retained to date. A balloter is not voting on only the most recently proposed changes, they are voting on all the proposed changes that have been retained-to-date. As a result, we recommend drafts showing only most recent changes also be accompanied by an additional redlined document which shows *all the proposed revisions retained to date*, and using the version under enforcement as a baseline.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro agrees with the changes to CIP-014, FAC-003, FAC-013 and PRC-023. However, on FAC-013, PRC-023 and PRC-026, BC Hydro offers the following comments and suggestions.

FAC-013-3 Project 2018-03 Standards Efficiency Review Retirements drafting team recommended the retirement of FAC-013-2. As stated in their June 7, 2019 petition to FERC, NERC determined that the standard is not needed for BES reliability, and should therefore be retired. BC Hydro suggest that a revision of FAC-013-2 is no longer warranted.

PRC-023-5 Through the inclusion of the Transmission Planner (TP) in Attachment B, Criterion B2, the proposed revision indicates TP's responsibilities of selecting the circuits subject to requirements R1 through R5. BC Hydro recommends that the TP functional entity be included in the Applicability section of the standard and the TP's responsibilities clarified in the language of the requirement.

PRC-026-2 Requirement 1 mandates that the Planning Coordinator (PC) use Near-Term Planning Assessment results to identify stability constraints associated BES elements. However, the Near-Term Planning Assessment would be conducted by Transmission Planners (TPs) and coordinated by their PC. If a TP fails to provide its PC the list of stability related BES elements, PC could be held non-compliant to PRC-026-2. The proposed draft does not identify the Transmission Planners (TPs) as a responsible entity. BC Hydro recommends that the Transmission Planner's role to timely provide its PC with the BES Elements meeting R1 criteria be reflected within the requirement, and TP functional entity be added to the Applicability section of the standard.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

MEC supports MRO NSRF comments.

The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No

Document Name	
Comment	

ReliabilityFirst offers the following comments for consideration.

1. PRC-026-2

    i. The revised Standard uses the capitalized term “Near-Term Planning Horizon,” but this term is not in the NERC Glossary. The term defined in the NERC Glossary is “Near-Term **Transmission** Planning Horizon.”

    ii. The revised Standard uses the capitalized term “Near-Term Planning Horizon” but this term is not in the NERC Glossary.

2. PRC-023-5

    i. Attachment B criteria B2 added the term in bold: “… instances of instability, Cascading, or uncontrolled separation, **that adversely impact the reliability of the Bulk Electric System** for planning events.” The bolded term is also used in FAC-011-4, and our comments are nearly the same: What is the meaning of “that adversely impact the reliability of the Bulk Electric System?” Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? Attachment B criteria B2 is open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term “… that adversely impact the reliability of the Bulk Electric System.”

    ii. There are references in R6 to version 4 of the Standard (PRC-023-4) that should be changed to reference the new PRC-023-5 Standard

    iii. Recommend update to the new format with the measurements placed under each requirement.

3. FAC-003-5

    i. While RF disagrees with the removal of IROL lines as a whole due to reduction of lines falling under the compliance standards regarding maintenance, the noted red-lined changes are recommended for approval as stated.

4. CIP-014-3

    i. For all these, references to planning events needs to be more clearly stated as being the planning events in TPL-001 Table 1.

CIP-014-03 R4.1.1.3 **This needs to be made clearer. I am reading this revision in several different ways, none of which I believe to be then intent of the change. I think the reference to planning events needs to be changed to single station or single station location event.**

Here are the two ways that I read the standard as proposed.

1) What are the planning events? Are they the subset of TPL-001 Table 1 P1 through P7 events that could cause the loss of the single station or substation location, or all facilities at a single voltage level in a station or substation? If so, the CIP standard should provide more detail on what assumptions must be made for the planning events, that differ from the same events when studied per TPL requirements.

2) Are the planning events additional contingencies after system adjustments, and with the single station or substation still out of service? If so, this is a significant change the severity of events that this standard addresses. Is this a requirement to study the station outage concurrent with a planning event?

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion has the same concerns with the term instability that we have previously shared both here and in regards to prvious versions of CIP-002. The current use of the term, without clarification that it is intended to be applied to wide area issues, could lead to misinterpretation of the intent and lead to inconsistent application of the standard.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

BHE does not agree with the changes to CIP-014

BHE agrees with the changes to FAC-013

BHE agrees with the changes to PRC-002

BHE agrees with the changes to PRC-023

BHE agrees with the changes to PRC-026

BHE agrees with EEI's response to this question. The EEI response conveys that the proposed changes to the CIP-014 Aplicability Section would break the alignment between CIP-014 and CIP-002.

Likes 0	

Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 5

Answer	No
Document Name	

Comment

Some changes seem to be minor and some require revisiting the methodology and more coordination. Unless there is a fatal flaw with the existing, the proposed changes create a more complicated process that impacts several Standards.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No
Document Name	

Comment

OGE has similar concerns expressed by MRO-NSRF on CIP-014 changes. The proposed CIP-014 change would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014. OGE recommends the SDT to ensure any changes made to CIP-014 conforms with CIP-002.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy disagrees with the proposed changes to CIP-014 as the changes proposed are not also being applied to NERC Reliability Standard CIP-002 - Attachment 1, criteria 2.6. The four (4) sub-parts of Applicability Section 4.1.1 in the current approved CIP-014 standard are based on a subset of the NERC CIP-002 Attachment 1 criteria. The proposed change to CIP-014 section 4.1.1.3 would bring inconsistency with the CIP-002 - Attachment 1, criteria 2. While we do not necessarily oppose the proposed revision, the SDT should also ensure the change is made to CIP-002 for consistency and the proposed changes would need to be more carefully considered for impact within the CIP-002 standard before we can fully support.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

ATC Supports the comments of the MRO NSFR and EEI.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	

Response

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter

Answer	No
Document Name	

Comment

Oncor supports the comments submitted by EEI for CIP-014.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

PacifiCorp does not agree with the changes to CIP-014 and supports EEI and MRO NSRF with their comments. The CIP-014 Applicability Section 4.1.1.3 comes from language in CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 filed CIP-002-6 with FERC for approval, which passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and changing the connection and synergy with CIP-002.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned with removing the Reliability Coordinator (RC) in the applicability of proposed CIP-014-3. The RC, as specified in the proposed FAC-014 standard, establishes Interconnection Reliability Operating Limits (IROLs) in accordance with its SOL methodology. Once identified in the operational horizon, however, the RC will likely adopt more conservative operational criteria to avoid instability, Cascading or uncontrolled separation. As Texas RE reads the current FAC-014 requirements, the Planning Coordinator (PC) and Transmission Planner (TP) will be required to plan using at least these more conservative Facility Rating, voltage limits, and stability criteria. The use of these more conservative limits in the Planning Assessment could potentially make it less likely that the TP and PC will ultimately identify instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System. As such, facilities currently subject to the CIP-014 requirements today would be potentially excluded from the scope of the proposed CIP-014.

Texas RE understands that the SDT's intent in revising the CIP-014 was not to change the substantive scope of the CIP-014 requirements. To ensure there is no inadvertent changes to the facilities subject to CIP-014, Texas RE recommends that facilities identified by the RC as causing instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System be retained in the scope of the CIP-014 requirements.

Texas RE has the following comments regarding proposed FAC-003-5:

- It is unclear how planning events that involve multiple elements (e.g. TPL-001-4 P6 event) would fall into the applicability of FAC-003-5. The applicability section of FAC-003-4 made it clear using the language of "Each overhead transmission line operated below 200kV identified as an element of an IROL…" FAC-003-5, however, simply uses the language "a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event." It is not clear whether each element that comprises the planning event or only a single line "that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System".
- The asterisk on Table 2 appears to be inconsistent with FAC-014. The asterisk is applicable only "if PC has determined such per FAC-014." FAC-014 includes both of the PC and TP in Requirements R6-R8. The footnote as written excludes the TP so it is unclear whether TP

Facilities, determined per FAC-014 R8, are subject to vegetation management. This could leave a gap in the reliable operations of the grid if the list of Facilities derived by the PC and TP are different. Texas RE recommends adding "and TP" to the footnote in FAC-003-5.

Texas RE noticed that the rationale for PRC-002-3 includes a reference to PRC-002-2 in Requirement R6. The Guidelines and Technical Basis Section also contain references to PRC-002-2 (e.g. Introduction Section, Guideline for Requirement R6, R7).

Texas RE has the following comments for proposed PRC-023-5.

Texas RE recommends Transmission Planner be added to Requirement R6 and the Applicability section of the standard. In section 4.2 Circuits, there are references to the lines selected by the Planning Coordinator in accordance with Requirement R6. Requirement R6, with the Planning Coordinator as the only functional entity type listed, references Attachment B of PRC-023-4. Attachment B contains an addition in B2 regarding the Transmission Planner selection of a circuit. As stated in the "Criteria" section of Attachment B: "If any of the following criteria apply to a circuit, applicable entity must comply with the standard". If Transmission Planner is not included, there could be a gap in the reliable operations of the grid if the list of circuits selected by the Planning Coordinator and Transmission Planner are different.

- Requirement R6 contains references to PRC-023-4 Attachment B (and Measurement M6 has similar reference.), which needs to be updated to PRC-023-5.

Texas RE has the following comments for proposed PRC-026-2.

- Texas RE requests the SDT consider capitalizing Transmission Line in Section A 4.2, Requirement R1, and Part 2.2 since it is a defined term.
- Texas RE requests the SDT to provide more clarification regarding the term "planning event". Texas RE recommends stating that the planning events refer to Table 1 in TPL-001. As written, registered entities could make their own definition of what a "planning event" is and that definition may not cover all TPL-001 events listed in Table1.

Texas RE has the following comments for the White Paper.

Texas RE inquires as to which definitions are being proposed. The white paper contains a revised definition of System Operating Limit. There is also a definition of System Voltage Limit posted for a different project phase. Texas RE recommends putting the definitions in the implementation plan so it is clear what is being proposed.

- Please ensure consistency with the standards with regards to capitalizing NERC Glossary Terms. For example, "Steady State" is capitalized and it is not a NERC Glossary term.
- On Page 3, there is nothing after i. Part 6.1.3
- "Real-time Monitoring" is capitalized in bullet 5 on page 5, bullet 2 of page 7, and bullet 6 of page 7. Real-time monitoring is not a defined term in the NERC Glossary and should not be capitalized.
- On page 4, Texas RE recommends using the language of the standard to describe the intent of the SOL concept within FAC-011. Texas RE recommends revising number 1. to "Facility Ratings, System Voltage Limits, and the stability performance criteria noted in R4".

- criteria noted in R4".
- On page 6 there is a discussion about maintaining SOL performance that includes a reference to "associated time parameters" for System Voltage Limits. As discussed previously, there is no time requirement stated within the definition of System Voltage Limits and therefore clarity is needed to implement the standards using System Voltage Limit and referencing a time duration.
- On page 6, Texas RE recommends revising "unit stability" to "angular stability" to match the Standard.
- On page 6, "Stability" should not be capitalized in the last sentence as it is not defined in the NERC Glossary. "Stability" is capitalized in the discussion about Voltage Stability Limits as well.
- Number 3 on page 6 references TOP-001-3. Since this project is proposing TOP-001-6, Texas RE recommends revising it to TOP-001-6.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

A common language has been utilized to revise these standards stating "that adversely impact the reliability of the BES". This language does not detail what is considered "adverse impact," and therefor introduces inconsistencies among the industry.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

Comments: AZPS supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014.

AZPS supports EEI's comments that changes made to CIP-014 are not necessary and these changes could have unintended consequences for the industry. Similar changes were proposed under Project 2016-02 and industry rejected the changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact.

Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry back in 2018 for CIP-002 remains unchanged. For this reason, we ask the SDT to not break the linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) creating unnecessary confusion.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	No
Document Name	

Comment

Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

PRC-002 - TVA disagrees with the proposal to change responsibility for PRC-002-3 R5 from the Planning Coordinator (PC) to the Reliability Coordinator (RC). We believe the responsibility for determining the need for DDR equipment should remain with the PC as this is better evaluated in the near-term planning horizon.

FAC-003 - On page 9, we recommend adding "…for a planning event" to the Category 1A description for consistency with the edits made for Category 1B, 2A, 2B, 4A and 4B.

CIP-014 - We agree with comments provided by several other entities regarding the proposed change to applicability section 4.1.1.3 creating a misalignment with CIP-002 - Attachment 1, part 2.6.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 7.

Likes 0	
Dislikes 0	

Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energys supports the following comments provided by EEI:

EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact.

Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

On behalf of Exelon, Segments 1, 3, 5, & 6

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT: The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets. In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact. Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	

The changes made to the Applicability Section of CIP-014 no longer align with CIP-002. We also note that the proposed changes to PRC-023-3 and PRC-026-2 referring to Planning Assessments no longer correspond to the language in PRC-002-3 which does not refer to Planning Assessments but refer to BES Elements that are part of an Interconnection Reliability Operating Limit (IROL) [Requirement R5, Part 5.1.4 as well as in the Guidelines and Technical Basis Section, Guideline for Requirement R5].

The use of the term ‘instability’ in CIP-014-3 represents a potential point of confusion. While the term ‘instability’ is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, while it is used in TPL-001-5.1 in the context of identifying “System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding” as defined and documented by each Transmission Planner and Planning Coordinator within their Planning Assessment.

There are also (minor) inconsistencies in the wording referring to identifying Facilities per Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, e.g., “planning events” in CIP-014-3 and PRC-023-3 vs. “a planning event” in FAC-003-5 and PRC-026-2 as well as variations in the wording related to the above reference to results from Planning Assessments in the sub-bullets of Requirement R1 of PRC-026-2. Please consider using consistent wording.

In addition, please consider an alternate approach for revising the Applicability criterion in Part 4.1.1.3 of CIP-014-3 such as: “Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.” This is essentially the same criterion as in CIP-014-2 without including the Planning Coordinator or Transmission Planner functional entities.

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern Company does not support adjusting the applicable entity in PRC 002 [R5] from TP/PC to RC for the Eastern Interconnect. TP/PCs are appropriately positioned to identify where dynamic Disturbance recording (DDR) data is required based upon their wide area view of reliability needs, particularly as it pertains to changing system conditions that can be best gauged in the near term planning horizon. Furthermore, this time horizon is more aptly suited for determining equipment installation requirements due to the lead-time associated with the installation of any BES equipment. Lastly, there are potentially significant implementation plan and timing concerns with shifting the applicability of existing requirements to another functional entity, that could correspondingly shift the location and amount of DDR coverage required. These implementation considerations would need to be addressed.

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
For each of these standards, the intent of this project was to replace the term IROL with the definition of an IROL. In doing this, the SDT also added Transmission Planner to the requirements. In the original standards, the requirements were for the Planning Coordinator to identify the IROL. This work was assigned to the Planning Coordinators as they have a global view of the interconnected transmission systems. While Transmission Planners do perform stability studies, it is the Planning Coordinators that have this overarching view of the interconnecting systems when they perform their studies, thus it should remain only the responsibility of the Planning Coordinator to identify those facilities that are the basis for these standards in stability violations equivalent to an IROL. ITC requests the SDT clarify the term Planning event with additional clarifying information. If the intent was for the contingencies to include the P0-P7 Planning event, clarify by using this terminology or be very explicit to identify that extreme events are not included. This clarification is requested in PRC-023 and PRC-026.	
Likes 0	
Dislikes 0	
Response	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
A common language has been utilized to revise these standards stating “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefor introduces inconsistencies among the industry.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No

Document Name	
Comment	

WAPA endorses the MRO-NSRF comments regarding the Implementation Plan being too short for the necessary adjustments and training.

as for the rest:

WAPA does not agree with the use of "degraded" in FAC-003-5 or CIP-014-3. Degraded is a concept pertinent to BES Cyber Systems, BES Cyber Assets, Protection System, or RAS meaning that normal functionality is compromised. The term makes sense in the context of Cyber Assets given that their capabilities or availability can be reduced, e.g., slower sample rate of telemetry for protection, loss of high speed communication-aided fault clearing but Zone 2 backup remains intact, induced misoperations or failures to operate, etc. In the context of the establishment of Facility Ratings (FAC-008-3 Requirement R6), degradation is not a consideration. In other words, Facility Ratings are established consistent with a Facility Ratings methodology (FAC-008-3 Requirements R2 and R3) that may typically use normal or expected System configuration as a precondition for determining the Equipment Ratings, of which there is serially-connected most-limiting equipment, that comprise the Facility. Transmission line Normal and Emergency Facility Ratings should already consider ampacity, sag, and conductor temperature rise over ambient, amongst many parameters, when established.

The concept of transmission or generation Facility degradation is difficult to describe because the degraded System state or configuration is ambiguous. Degraded could refer to a myriad of abnormal System states, including: n-X prior outages, flows immediately post-Contingency, congestion requiring market redispatch, off-nominal System inertia due to displacement of conventional spinning mass generation with renewables, etc. Transmission Owners and Generator Owners do not publish reams of Facility Ratings considering every possible degraded state, nor would it be achievable for operating entities to use this information. In fact, take the simple example of Dynamic Line Ratings or Ambient Adjusted Ratings. Firstly, only a minority of North American transmission lines are currently operated with temperature-adjusted Facility Ratings. And, in most cases Transmission Planners and Planning Coordinators employ static Facility Ratings for the purposes of steady-state assessments, only invoking any consideration of temperature adjustment after identifying post-Contingency failures to meet System performance requirements of TPL-001-4 (soon -5) Table 1.

It is a fundamental Facility Ratings concept, reinforced by the Glossary of Terms definition, that Emergency Ratings have an associated duration. Therefore, WAPA disagrees with any approach to a calculated post-Contingency exceedance of a Normal Facility Rating that does not give some consideration of the duration the exceedance may persist before mitigation. Frankly, with the interest in reliability in mind, the SDT should not want to imply Transmission Planners and Planning Coordinators ignoring the headspace between Normal and Emergency Facility Ratings by only considering exceedances of Emergency Facility Ratings appropriate for Corrective Action Plans. To do so would be to plan the transmission system such that Normal Facility Ratings were irrelevant and essentially to state that all Normal Facility Ratings exceedances will be mitigated in the Operations Horizon; which we know to be poor planning and not always possible.

WAPA disagrees that the draft FAC-003-5 Applicability, Part 4.2.2 that infers flexibility that allows the Planning Coordinator or Transmission Planner to judiciously identify "a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event." On the contrary, this is a prescriptive inclusion that obligates the Planning Coordinator or Transmission Planner to perform unique analysis in addition to the requirements of TPL-001-4 (and -5). WAPA hopes that the SDT will remember that TPL-001-4 (and -5) Requirement R2, Part 2.7 requires the Planning Assessment to include Corrective Action Plan(s) addressing how failures to meet System performance requirements will be met; it does not require the Planning Coordinator or Transmission Planner to identify degraded Facilities that may be expected to result in instability, Cascading, or uncontrolled separation.

While annual Planning Assessment practices vary, instances of instability, Cascading, or uncontrolled separation that maybe mitigated by allowable Table 1 Interruption of Firm Transmission Service and/or Non-Consequential Load Loss will likely have no Corrective Action Plan developed and, thus, would not be reported as part of an annual Planning Assessment. WAPA has concerns that the "expected to result in instances of instability, Cascading, or uncontrolled separation" draft language is vague enough to imply that typical annual Planning Assessments that document Corrective Action Plans for instability, Cascading, or uncontrolled separation that are failures to meet System performance requirements of Table 1 will become insufficient. The result, we foresee, is that Transmission Planners and Planning Coordinators will become obligated to document every instance of instability, Cascading, or uncontrolled separation that they observe during analysis supporting their annual Planning Assessment, not just those instances that required Corrective Action Plans.

To summarize our comments:

The use of "degraded" Facilities is vague and should be removed from all proposed instances from FAC-003-5 and CIP-014-3.

The use of "adversely impacts the reliability of the Bulk Electric System" is redundant and should be removed from all proposed instances from PRC-023-5, CIP-014-3, FAC-011-4, and FAC-014-3.

WAPA greatly appreciates the time and attention that the SDT has made to each of the Reliability Standards affected by the "raising of the bar" for SOLs. Your work is necessary and relevant! Thank you for the opportunity to provide comment.

Likes 0	
Dislikes 0	

Response

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be further investigated and considered as part of this project:

- The changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be "critical to the derivation of" IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the "instability, Cascading, and uncontrolled separation" language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.

- PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.
- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section 4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:
    - "Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18 month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment	
Connditionally Yes - Request clarification of the phrase “adversely impacts” for impacted Standards. For example, the first FAC-003 instance reads: 4.3.1.2 Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that "adversely impacts" the reliability of the Bulk Electric System for a planning event… Please confirm the phrase “adversely impacts” has the exact meaning as the NERC Reliability Standards Glossary defined phrase “Adverse Reliability Impact”; if different, please define phrase "adversely impacts". Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates support the proposed revisions to FAC-003. However, the revised language is somewhat ambiguous, and we would appreciate the Drafting Team providing clarification on how the revisions apply to lines under 200kV described in 4.2.2. The conditions described in the revised FAC-003 affecting lines under 200 kV would not occur without being in violation of planning requirements of TPL-001-5 and TPL-001-4, which require looking to the future and mitigating where a single outage may result in a stability issue.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
With regards to standards revisions or deletions to FAC-010-3, FAC-011-3, and FAC-014-2 requirements for determining and communicating SOLs used in the reliable planning and operation of the BES, BPA agrees with the associated changes to FAC-003, FAC-013, PRC-002, PRC-023, and PRC-026. Regarding CIP-014-3, it is unclear how the Planning Assessment performed by the Planning Coordinator or the Transmission Planner in Applicability criteria 4.1.1.3 relates to the risk assessment performed by the Transmission Owner in Standard Requirement R1. BPA suggests the following edits to criteria 4.1.1.3 to help clarify.	

4.1.1.3. “Transmission Facilities that are identified by the Planning Coordinator or Transmission Planner through its Annual Planning Assessment of the Near-Term Transmission Planning Horizon, at a single station or substation location that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events.”

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

In our opinion CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5

Answer	Yes
Document Name	

Comment

Hydro-Québec Production agrees with the changes to PRC-002. We are not impacted by the other standards.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3

Answer	Yes
Document Name	

Comment

IPL offers no further comment.

Likes 0	
Dislikes 0	

Response

Gul Khan - Oncor Electric Delivery - 1 - Texas RE

Answer	Yes
Document Name	

Comment

Oncor supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes
Document Name	

Comment

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

Requirement R6 and 6.1 of the draft PRC-023-5 continue to reference PRC-023-4 Attachment B. Wondering if that's intentional or an oversight which should reflect version 5 instead of 4 of PRC-023? Additionally, the Implementation Plan still references PRC-023-4 instead of PRC-023-5 and should be reviewed due to a spelling error of "its" on page 4 following *conduct* and prior to *first assessment* that should be corrected.

Likes 0	
Dislikes 0	

Response

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey

Answer	Yes
Document Name	

Comment

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be furthe investigated and consideed as part of this project:

- For example, the changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be "critical to the derivation of" IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the "instability, Cascading, and uncontrolled separation" language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.

- Another example is PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.

- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section 4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:

"Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

- The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18-month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

Maurice Paulk - Cleco Corporation - 1,3,5,6

Answer	Yes
Document Name	

Comment

See SEE, EEI and MISO comments

Likes 0	
Dislikes 0	

Response

Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

NO.

NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.

Additionally, NERC has a SER project. Project 2015-09, Establish and Communicate, System Operating Limits, proposals create more redunancies; counter to the purpose of the SER project.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli

Answer	
Document Name	

Comment

Xcel Energy recommends a longer implementation plan due to the coordination and potential tools required.

Likes 0	
Dislikes 0	

Response

Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC

Answer	
Document Name	CIP-014 SBS Comments 8-3-2020.docx

Comment

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	6/19/2020
Comment Period End Date:	8/26/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 3 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 3 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 3 OT 2015-09 Establish and Communicate System Operating Limits IRO-008-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-002-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 AB 2 ST 2015-09 Establish and Communicate System Operating Limits TOP-001-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 173 different people from approximately 119 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
PPL - Louisville	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF

Gas and Electric Co.					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC

ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC

Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					John Hasting	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC

					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc	2	MRO
					Tim Miller	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					will Tootle	Southwest Power Pool Inc.	2	MRO

					Charles Cates	Southwest Power Pool Inc.	2	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

I agree SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. However, the standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. Otherwise it becomes more of a guideline that is difficult to enforce. It appears each Reliability Coordinator has some flexibility to develop it's own method for identifying SOL exceedances in its SOL methodology. If so, then what is going to prevent two adjacent Reliability Coordinators from arriving at different conclusions and having disagreements during Real-time operations? What is going to prevent two adjacent Transmission Operators in different Reliability Coordinator Areas from having disagreements? What is going to prevent disagreements between Registered Entities and their Regional Entity? How are those disagreements resolved? The purpose of the SOL Whitepaper was to establish a common understanding of SOL exceedances across North America. Hopefully these requirements are not detrimental to that effort and the purpose of this project.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Past proposed revisions from the SDT drew comments that our offerings provided too little flexibility for RC's to determine what was appropriate within their footprint for SOL exceedance determination. This resulted in the currently proposed FAC-011-4, R6, which the SDT has offered as a framework within which each RC can determine SOL exceedances. The framework, coupled with

FAC-011-4 requirements R1, R2, R3 (specifically R3.5) and R4, require use of common ratings, voltage limits and stability criteria across their RC footprint. Based upon feedback received during the SDT's efforts, dictating specific rating, voltage limit and stability criteria for use across all RCs was not supported by industry. Allowing asset owners to rate their facilities per FAC-008, and provide those ratings per FAC-011-4, R2, seemed a reasonable approach supported by industry. Determining common voltage limits for use by the RC and its TOPs via FAC-011-4, R3, seemed reasonable based upon industry comment, with subpart R3.5 requiring documentation of the method used to manage voltage limit differences that you note in your question. FAC-011-4, R4, sets a minimum set of common stability criteria for all industry, while allowing RCs to add additional criteria per their needs, which also has been largely supported by industry. The RC, and its SOL methodology, are the arbiter of disagreements on SOLs and SOL exceedances within their footprint, and existing standards already require when there is a disagreement, the lowest rating or limit be used when two RCs or TOPs cannot agree on the appropriate limit to use. Those situations exist today and are resolved successfully by this existing standard practice, when agreement cannot be achieved. Therefore, the SDT believes that the proposed FAC-011-4 provides an industry-supported balance between clarity and flexibility when establishing SOLs and setting a framework for their use in determining SOL exceedances, and further specificity and flexibility elimination would not me supported by the industry at large.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Thank for your comment. Please see our response to John Allen's, City Utilities of Springfield, Missouri, comments.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	

In consideration of past confusion related to whether an SOL exceedance is a regulatory violation, LES suggests the following changes to better clarify R6: **R6.2.1** Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. *[Remove: Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.]* **R6.2.3 Predetermined stability limits are not exceeded.** *[Remove: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.]*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT discussed at length the language noted in R6.2.1 and believes it should be retained for clarity. Furthermore, the SDT believes the language in R6.2.3, including note 1, provides the option of using either pre-determined stability limits or real-time stability analysis, since both options would meet the stability criteria in the RC's SOL methodology.	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
R6.1: The way this is worded is awkward and confusing. Why are you using the language "no contingencies" instead of "pre-contingency state"?	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT discussed what “pre-contingent” conditions meant, and indicated that in actual operations, there are always planned and forced outages present. We thought using the “no contingencies” phrasing better described the system, as it is currently, before application of any new contingencies, as a better description than simple the “pre-contingency state”.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Thank you for your comments. With respect to the comments provided for Q1, this response will address each of the bulleted items in your comments. With regard to item 1, the SDT discussed at length whether to use Facility Ratings or Normal and Emergency Rating. The SDT, with the aid of observers, settled on the use of Normal and Emergency Ratings. However, the construct of FAC-011-4, R6, parts R6.1.1 and R6.1.2 still work if the rating set in use is respected, the highest rating in use is not exceeded, and any time duration associated with the ratings are respected. R6 does not require the creation and use of Emergency Ratings. FAC-011-4, R2 requires a method be provided by the RC, in its SOL methodology, for the TOPs to determine which Facility Ratings provided by the owner are to be used in operations. With regard to item 2, the SDT discussed the use of the phrase “determining common“ in FAC-011-4, R3, part R3.5. The language notes a number of potential sets of voltage limits, between RC and its TOPs, adjacent TOPs and between adjoining RCs. The language does not require establishing common voltage limits, on the method for determining common voltage limits. An RC and its TOPs should be using the	

same of voltage limits, so the use of the phrase makes sense. In the latter two examples, if common voltage limits can be achieved, that is a desirable outcome, but if not, the method should describe how the voltage limits will be used, which achieves coordination. With regard to item 3, the SDT believes there is a misunderstanding of the intent of FAC-011-4, R6, part 6.1.3. The language in part 6.1.3 does not preclude an RC adding additional criteria, such as enumerated in your comment, for pre-contingent conditions. The SDT merely included the language in part 6.1.3 as a floor; if not pre-contingent stability limits existed, then other criteria, as established by the RC, would need to be met. With respect to item 4, the SDT recognizes that the term "modify" does not exist in the FAC-011-4 standards noted in the comment (5.2 and 4.4), but fails to see how the language in proposed FAC-011-4, R4 and R5, parts R4.4 and R5.2, respectively, eliminate clear guidance and flexibility (as noted in the comment). The two standards speak to how stability limits are determined and contingency lists expanded, respectively, and are silent on their means of modification. The proposed language does not preclude modification, and would not prevent an SOL methodology describing how either stability limits or contingency lists may be modified. With respect to item 5, the SDT discussed at the language noted in the comment in the existing standard (FAC-011-3, R2, part R2.3.1). The SDT determined that load lost as a consequence of tripping the faulted element did not need description in the revised FAC-011. As a result, the noted language was not retained. With respect to item 6, the SDT discussed, at length, pre and post contingency conditions and states, and how they relate to SOL exceedance determination. With the changes made to the SOL whitepaper, and understood existing use of the terms in industry, the SDT did not see the need for defining the terms in the NERC glossary.

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	No
Document Name	
Comment	

FMPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to John Allen's, City Utilities of Springfield, Missouri, comments.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA suggests the proposed TOP-001-6 requirement R25 be removed. BPA believes the requirement that the TOP use the RC SOL methodology for establishing SOLs in the Operations horizon is already covered in FAC-014 R2. The proposed FAC-011-4 R6 will require the RC SOL Methodology to explicitly include applicability to "Real-time monitoring, Real-time Assessments, and Operational Planning Analysis". (Using the RC West SOL Methodology as an example, the applicability of the methodology to these sub-horizons is already explicit in the document.) BPA believes the proposed TOP-001-6 R25 is redundant and simply adds to the burden of compliance documentation. BPA has no concerns with the proposed revisions to IRO-008-3 R5/R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. AS the SDT reviewed the standards, we thought there was a benefit to the clarity brought by the addition of R25 to TOP-001-6 with regard to SOL exceedances, in terms of which SOL methodology should be used. FAC-014-3 R2 speaks only to SOLs, not SOL exceedances.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	No
Document Name	
Comment	

Texas RE appreciates the standard drafting team's (SDT) efforts to clarify System Operating Limit (SOL) exceedance use and determination. As Texas RE understands it, proposed FAC-011-4 Requirement R6 establishes the required system performance framework in an RC's SOL methodology for determining SOL exceedances in the RC's Real-time monitoring, Real-time Assessment (RTA) and Operation Planning Analyses (OPA) activities. Texas RE remains concerned, however, that proposed FAC-011-4 could be read to permit the broader use of less conservative Facility Ratings in identifying and responding to SOL exceedances by permitting entities to operate the system without identifying an SOL and implementing an Operating Plan when: (1) pre-contingency steady state flows are within Emergency Ratings in circumstances in which System adjustments to return the flow to within a Facility's Normal Rating could be executed and completed within the applicable time duration of the Emergency Ratings; and (2) post-contingency flows through Facilities are within the Facility's highest Emergency Rating.

Regarding post-contingency flows in particular, Texas RE is concerned that entities would not be required to identify post-contingency flows and voltages above a Facility's two-hour Emergency Rating as an SOL. Texas RE notes that the "highest Emergency Rating" is usually an extreme limit associated with a very short duration to mitigate an exceedance of the Emergency Rating. For example, ERCOT ISO utilizes a 15-minute rating (along with 2-hour and continuous) that is defined as shown below:

"The 15-minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading up to 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading up to 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current."

As Texas RE reads the proposed FAC-011-4, R 6.2.1 language, SOL methodologies could be designed to permit post-contingency flows above a Facility's two-hour Emergency Rating but below the highest 15-minute rating. By possibly not requiring entities to identify this instance as an SOL exceedance in its OPA or RTA, an entity would correspondingly not be required to create an Operating Plan to mitigate the exceedance and would not be required to take pre-emptive steps to address such post-contingency flows identified in Real-time. In turn, if an Operating Plan is not created, the entity potentially would not know the adjustments needed to address the exceedance and the duration in which these adjustments can be completed.

Texas RE observes that the proposed NERC System Operating Limit Definition and Exceedance Clarification provides: "Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event."

Texas RE supports this approach, but believes additional clarity is necessary in the Standard Requirement language itself to require entities more proactive action to address post-contingency identified Emergency Rating exceedances rather than only requiring entities to develop Operating Plans when exceedances of the highest Emergency Rating are identified.

Additionally, Texas RE recommends the SDT consider the following:

- In Part 6.1, rephrase "System performance for no Contingencies demonstrates the following to "System performance **where there are no applied** Contingencies demonstrates the following". Alternatively, "applied" could be moved to be after "Contingencies".
- In Part 6.1.2, there is typically no time duration associated with voltage limits, nor is there a reference to time duration in the proposed definition of System Voltage Limits. Based on this language it should or a SOL exceedance for a System Voltage Limit may not occur based on this language. The reliability of the grid could suffer by never returning to "normal" System Voltage Limits because no time duration is specified.

- In Part 6.2.1 “Steady State” is capitalized (and also capitalized in the rationale document in several places), but there is no current or proposed definition in the NERC Glossary. Texas RE has experienced entities asking about a definition during recent engagements.
- Additionally, within Part 6.2, there may need to be a reference regarding “Predetermined stability limits are not exceeded”. It would appear that the omission would allow a “predetermined stability limit” to be exceeded for a single contingency and thus meet system performance, which seems to contradict an N-1 approach to reliable operations.
- Part 6.1.2 states “System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.” The proposed definition of System Voltage Limit does not define a time period. So there nothing to describe what the “specified time duration of those emergency System Voltage Limits” is. Texas RE recommends the System Voltage definition include a time duration to be more effective, reliable, and applicable.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. First, with regard to your concerns about Emergency Rating use and their applicable timeframes, the SDT attempted to include language as you describe in our 2nd posting, and that version did not gain adequate industry support. To be more specific, the SDT attempted to include language that would call out as SOLs any potential operation outside of the time limits of any emergency rating. The industry did not provide adequate support for that proposal. With the language in the current offered revision of FAC-011-4, operation outside of “applicable facility limits” or “the specified time duration of those Emergency Ratings” is not allowed, whether it is called an SOL or not. Since it is not allowed, an operator would have to develop an operating plan to operate within those emergency ratings. In addition, nothing prevents an RC from choosing to write its SOL methodology such that operation as described in your comment would be considered an SOL in that footprint.

With regard to your comments on the wording of Part 6.1, we considered your language but chose to retain the original, given that is achieved the required level of industry support.

With regard to your comment on the capitalization of “Steady State”, we reviewed it and removed the capitalization if warranted.

With regard to your comment on Part 6.2, and specifically to Part 6.2.3, the language in Part 6.2.3 and note 1 should not allow a pre-determined stability limit to be exceeded, since it should have been established to prevent one or more of the stability criteria in the RC's SOL methodology from being met. Finally, with regard to your comment on Part 6.1.2, our SDT's discussion on voltage limits noted that there were entities which included a time duration with their voltage limits, so we recognized that the standard should account for this concern. In addition, we did not think the standard should arbitrarily establish a time duration for voltage limits, which should instead account for operational considerations and asset owner information on the equipment's voltage limits.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT attempted, through creation R6 in FAC-011-4, to establish a common framework for SOL exceedance determination with each RC's footprint. The SDT, however, did not think it could establish a means by which to have the same criteria for SOL exceedance determination across all RCs. Instead, the SDT sought to provide clarity on the determination and use of thermal and voltage limits, set a minimum set of common stability criteria, and still allow the use of the long-standing practice of operating to the most limiting criteria where two entities have criteria differences.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to EEI.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to EEI.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No

Document Name	
Comment	

NV Energy supports the comments provided by EEI:

While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring "predetermined stability limits" to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the "stable performance criteria defined in the Reliability Coordinator's SOL methodology" to be met, based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2.

Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Please see our response to EEI.

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
While the latest modifications are an improvement over the previously proposed modifications, EEI does not support certain changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. Specifically, the proposed FAC-011-4 modifications contain requirements related to the establishment of limits, contingency events, and performance framework that eliminate a necessary level of flexibility and clarity that currently exists in the FAC-011-3 Reliability Standard. Requirement 6, subpart 6.1/6.1.3 of FAC-011-4 affords entities little flexibility when determining stability performance for system conditions with no contingencies by requiring “predetermined stability limits” to not be exceeded. (R6.1) This seems to be in contrast with the flexibility afforded for single contingency conditions, which require the “stable performance criteria defined in the Reliability Coordinator’s SOL methodology” to be met,	

based on predetermined stability limits or adjusted with real-time or offline analysis techniques. (R6.2). EEI suggest that R6.1.3 be removed or revised to more closely aligned with R6.2. Additionally, the implementation plan proposed by the SDT should be extended to account for the extensive work that may be required by responsible entities to document and track what is expected to be a significantly larger numbers of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Many entities may need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. New servers and other associated hardware, as well as software modifications may be necessary to meet these new logging requirements to track exceedances of very short duration and to record mitigation responses for every SOL exceedance regardless of the duration. This situation is further complicated for those entities using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe should be extended to a minimum of 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT discussed what it meant to be stable in the "pre-contingent state" and could not see where a system, if stable, would not remain stable unless perturbed in some way. Since many in industry maintain stability by monitoring pre-contingent interfaces, that seemed logical to include in the standards (and was as Part 6.1.3). Any perturbation could be construed as a "contingent event," so Part 6.2.3, with note 1, was seen as flexible enough to account for all possibilities. The SDT did discuss adding more language in part 6.1.3, but industry comment suggested that would put in jeopardy approval of FAC-011-4. With regard to your comments on the extension of the implementation plan timeframe, the SDT has agreed to extend it to 24 months.	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	

Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT discussed what it meant to be stable in the "pre-contingent state" and could not see where a system, if stable, would not remain stable unless perturbed in some way. Since many in industry maintain stability by monitoring pre-contingent interfaces, that seemed logical to include in the standards (and was as Part 6.1.3). Any perturbation could be construed as a "contingent event", so Part 6.2.3, with note 1, was seen as flexible enough to account for all possibilities. The SDT did discuss adding more language in part 6.1.3, but industry comment suggested that would put in jeopardy approval of FAC-011-4. With regard to your comments on the extension of the implementation plan timeframe, the SDT has agreed to extend it to 24 months.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
ACES believes that the revisions made by the SDT will improve the reliability with regard to SOL exceedance. However, it does not provide consistent framework for defining SOL exceedances for all registered entities. Therefore, two adjacent Reliability Coordinators can reach different conclusions to address a common event during real-time operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT attempted, through creation R6 in FAC-011-4, to establish a common framework for SOL exceedance determination with each RC's footprint. The SDT, however, did not think it could establish a means by which to have the same criteria for SOL	

exceedance determination across all RCs. Instead, the SDT sought to provide clarity on the determination and use of thermal and voltage limits, set a minimum set of common stability criteria, and still allow the use of the long-standing practice of operating to the most limiting criteria where two entities have criteria differences.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to EEI.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA partially agrees with the SDT revisions that address how SOL exceedances are determined and used in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. The flexibility afforded to each Reliability Coordinator to determine its own framework based upon its SOL methodology is an absolute must, but the concept of “a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments” is problematic and vague. It is noted that the concept of a “risk-based approach” does not carry over into the actual selection of single or multiple Contingency events which is a core tenet of the existing FAC-011-3. Incorporating aspects of risk are essential to the establishment of SOL exceedances (e.g., defining credible multiple contingencies) and should be addressed in each Reliability Coordinators SOL methodology, but this perpetuates the confusion that has plagued the existing FAC-011-4 and elsewhere.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The risk-based consideration in R7 in FAC-011-4 was included with regard to the expected increase in identified SOL exceedances with the industry use of FAC-011-4, as well as its associated changes in TOP-001 and IRO-008. Based on industry comment, there was recognition by the SDT that all SOL exceedances to be communicated between TOPs and RCs may not be reasonable, and the application of a risk-based filter to require or focus on those SOL exceedances that had higher risk (for example IROLs or SOLs that may easily become IROLs) and allow the communication of lower risk SOLs to be weighted less, seemed logical, was accepted by the SDT members and thought practical by the observers in attendance. Rather than be more prescriptive, the SDT thought the application of the risk-based filter would promote reasonable consistency and flexibility with regard to SOL exceedance communication, with the sub parts adding minimum expectations.	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	
FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes. PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The revisions in FAC-011-4 were targeted to improvement of the FAC-011 standard and the RC's SOL methodology and not to alignment with planning horizon studies. The drafting team took into consideration comments from the SDT members, group observers and comments throughout the posting process, which the result being the current proposed FAC-011-4. The SDT has a number of RCs as members, and their comments coupled with those of other RC commenters during the posting process have not noted this as a concern. Since the SDT is suggesting an extension of the implementation time to 24 months, all parties should have adequate time to discuss and address any such concern.	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

While FAC-011-4 requires the RC to Provide Planning Coordinators and Transmission Planners with the RC Methodology, FAC-014-3 does not allow the Planning Coordinators and Transmission Planners to respond to the RC established SOLs and requirese the Planning Coordinators and Transmission Planners to establish their own SOLs that are equally limiting or more limiting than the RC established SOLs.

What if there is a technical problem with the RC established SOLs. There is not listed recourse in FAC-014-3 for the PC or the TP to provide comments on technical problems with the RC established SOLs and a requirement that the RC address those problems.

Clark Public Utilities is a small utility and as a TP, it doubts that the RC West is going to be very concerned about Clark's small area of 115 kV transmission. RC West has already informed Clark by email that it will only be in direct contact with its BA and TOP members and Clark need to go through its TOP (Bonneville Power Administration) to deliver its annual Transmission Planning Assessment. FAC-011 and FAC-014 need to address the changed relationship between non-BA and non-TOP entities in the West that are part of the RC West Reliability Coordinator footprint.

RC West's relationship with non-BAs and non-TOPs is different that the Peak RC relationship, RC West seems only to want to deal directly with the larger organizations. While this may only be a situation in the West, NERC should look closer at what the RC to other entity relations should be so the overall compliance can be more efficient and so that smaller entities are not creating work that is not going to be used. That is just paper pushing to make sure a compliance box is checked off and is not doing anything to assure reliability.

Clark believes that the relationship heirarchy for the Operating Horizon should be from the RC to the Planning Coordinator to the Transmission Planner. The Planning Coordinator should develop its SOL Methodology using the RC Methodology and RC Contingincies for the Operating Horizon and its own methodology and its own contingencies for the Planning Horizon. The PC should distribute its methodology and contingency list to Transmission Planners in its footprint. TPs then should have the ability to coordinate their own contingincies with the PC provided contingincy list. Once that is done (i.e. the TP and PC agree on the contingencies to be used in studies) the TP should then establish its SOLs for the Operating Horizon and Planning Horizion and provide those to its PC for comments and revision or approval. The PC should provide its consoldated SOLs for the Operating Horizon and Planning Horizion to the RC for comments and revision or approval. Then the RC should provide the final approved list of SOLs for all PCs and TPs in its footprint to all TOPs in its footprint.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. While the SDT can appreciate the complexity of the situation you have described, we, as a group, have discussed at length whether SOLs belong in planning or not. SOLs, or system operating limits, were determined to only be a construct used in the operation of the system. As such, they were and are used by RCs and TOPs. The SOLs are based upon thermal limits, voltage limits, and stability limits drawn from application of stability criteria, so there are corresponding values used in planning the system.

The revisions to the FAC-014 standard focus on the standard and reliability, and do not dictate how entities interact with one another beyond determining entity responsibility for reliability functions. Unfortunately, your request is inconsistent with the direction we have been given by industry, so the SDT cannot pursue it at this time.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment

FAC-014-3 No

The FAC-014-3 R6 language opens the door for the Reliability Coordinator (RC) to dictate to the Transmission Planner (TP), through the RC's SOL methodology, the following items used in planning assessments: facility ratings, voltage criteria, and stability criteria. Establishment of facility ratings are the responsibility of the TO under FAC-008, while establishment of voltage and stability criteria are the responsibility of the TP under TPL-001-4. These responsibilities should not be ceded to another party. Long term implications are that the RC, through control of such items as facility ratings, voltage and stability limits, could force a TO to enter into corrective action plans and associated capital expenditures that they otherwise would not.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT discussed the RC's role, and after review of FERC orders and the reliability standards, the RCs are the ultimate operating authority and can determine the thermal ratings, voltage criteria and stability criteria they will use when operating the system. However, FAC-011-4 has been written such that the RC will use the facility owner's offered ratings (thermal and voltage) to see how they may be used to fulfill the thermal ratings and voltage limits the RC requests to operate the system. As such, the RC does not dictate ratings. It does select stability criteria, and this is based upon the need to operate the system reliably. That is why the SDT included in FAC-014-3 the new R6 requirement for creation of a process, by the PCs and TPs, to confirm Facility Ratings, voltage limits and stability criteria are at least as conservative as those in its respective RC's SOL methodology, or provide a technical rationale why that is not the case. This review should provide an opportunity for any PC, TP and RC to discuss and resolve differences in those limits or criteria sets.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments". The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent	

framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint. However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed." The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. We have considered your suggested rephrasing of FAC-011-4, R6.4. However, our discussion focused on the fact that this evaluation is performed when determining operating plans to mitigate SOL exceedances, and does not preclude an operator, when managing the system, to the take actions they deem necessary to maintain reliability of the system.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. We are extending the implementation time to 24 months based upon the preponderance of comments.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO-NSRF.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
MEC supports the MRO NSRF comments. The MRO-NSRF agrees with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. The MRO-NSRF supports the proposed revisions to FAC-011-4, Requirement 6, which while providing a consistent framework for defining a SOL Exceedance within the RC methodology, also provides some flexibility to each RC in the application of the framework within its footprint.	

However, the MRO NSRF does recommend a change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although the MRO NSRF understands the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed." The MRO NSRF notes there remains the potential for differences between adjacent Reliability Coordinators over the methods used to identify SOL exceedances.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We have considered your suggested rephrasing of FAC-011-4, R6.4. However, our discussion focused on the fact that this evaluation is performed when determining operating plans to mitigate SOL exceedances, and does not preclude an operator, when managing the system, to the take actions they deem necessary to maintain reliability of the system.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NSRF.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Please see our comments in Q#2 and Q#4	
Likes 0	
Dislikes 0	
Response	
Please see our responses to those comments.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports comments submitted by EEI. Dominion agrees that the implmentation period should be extended to allow entities the appropriate time to make changes to complex systems and processes.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see responses to EEI. We are extending the implementation time to 24 months based upon the preponderance of comments.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	Yes
Document Name	
Comment	

OGE agrees with MRO-NSRF's comments on replacing IROL definition language with "Adverse Reliability Impact" as shown below:

Proposed Language:

FAC-011-4, Parts 6.1.4 and 6.2.4. Adverse Reliability Impacts do not occur. 1

Footnote 1, page 5: Stability evaluations and assessments of Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that Adverse Reliability Impacts do not occur.

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of Adverse Reliability Impacts

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. After due consideration, the SDT has chosen to retain its existing language.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to MRO NERC Standards Review Forum.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC appreciates the changes made by the SDT to address industry concerns and we are supportive of the current revisions to these standards. We do recommend one change to FAC-011-4 R6.4 language. Specifically, the proposed language reads, "planned manual load shedding is acceptable only after all available System adjustments have been made." Although we understand the intent of this language (i.e. load shed is a last resort solution), we don't believe it is the SDT's intention to require every System adjustment to actually be implemented in a study or model prior to determining that manual load shed is the best planned response. We believe the intent is to ensure all available adjustments have been appropriately assessed before deciding on the solution of last resort. We recommend changing the language to, "planned manual load shedding is acceptable only after all available System adjustments have been assessed."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We have considered your suggested rephrasing of FAC-011-4, R6.4. However, our discussion focused on the fact that this evaluation is performed when determining operating plans to mitigate SOL exceedances, and does not preclude an operator, when managing the system, to the take actions they deem necessary to maintain reliability of the system.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	

Comment	
FAC-014-3 The statement “any instability identified in its Planning Assessment of the Near-Term Transmission…” seems unclear. I think an improvement and more clear statement might be, “any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…”. The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We attempted with the language to be as concise as possible. Since Corrective Action Plans would only be developed for cases of instability for any stability criteria violation, we believe the language in the standard would have the same result as your suggested language revision.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
We agree with the revisions but offer the following for consideration and improvement. a. Requirement R7 – plural word “communications” needs to be changed to be singular.	

b. The proposed modification to IRO-008 requirement R6 effectively requires the RC to notify TOPs and BAs when SOL exceedances have been mitigated or prevented in accordance with its SOL Methodology; however, there is no specific requirement in proposed FAC-011-4 that requires the SOL methodology to address notification of SOL exceedance mitigation or prevention. It only specifically requires the SOL methodology to addresses notification of SOL exceedances. While it is true that proposed FAC-011-4 requirement R7 can be interpreted to include not only notification of SOL exceedances, but also notification of SOL exceedance mitigation or prevention, it might be clearer to enhance FAC-011-4 requirement R7 by specifically addressing notification of SOL exceedance mitigation and prevention. If this modification is not made, RCs might not know that their SOL methodology is supposed to address notification of SOL exceedance mitigation and prevention if they don't happen to read proposed IRO-008 requirement R6. Potential language enhancement could be "Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances (and associated exceedance mitigation) identified as part of Real-time monitoring and Real-time Assessments must be communicated…"

Likes 0	
Dislikes 0	

Response

Thank you for your comments. We have removed the "s" on communications as you have suggested. With regard to your larger point regarding SOL exceedance communication, we were clear in our discussions of R7 in FAC-011-4 that the methodology requested would deal with all aspects of SOL exceedance communication. If the IRO or TOP standards required communication on SOL exceedances, we expect the methodology created per R7 to account for those required communications. We do not believe the standard language needs revision, but we will expand upon the rationale document to include this explanation.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	Yes
Document Name	

Comment

Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.

Likes 0	
Dislikes 0	
Response	
Thank you for the comment. We are extending the implementation time to 24 months based upon the preponderance of comments.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We believe the future for SOL communication will require automation for exceedances to be logged and reported, as based on RC and TOP methodology. We have concerns with an increase in data logging requirements and ask the SDT to look at TOP-001 and we question whether it is the best place for specifications for determining real-time assessments? Perhaps it is better in TOP-002? Also we believe an SOL needs to be clearly defined and not open to interpretation from region to region. In addition, we believe that a 12 month implementation plan wouldn't allow enough time to incorporate these new changes, to procure hardware and software, and therefore we ask that a 30 month implementation plan be implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. We are extending the implementation time to 24 months based upon the preponderance of comments.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	

Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. We are extending the implementation time to 24 months based upon the preponderance of comments.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the direction of the changes made to FAC-011-04, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations. However, the implementation plan should be extended to account for the additional work by responsible entities to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-6 Reliability Standards. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to track accurately exceedances and validate exceedances. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months. ITC believes however that in a similar way that industry responded to FAC-015, the same concerns exist for FAC-014-3 R7. Transmission Planners refer to TPL-001-4 (-5). It seems misplaced to have a requirement concerning the Near Term Assessment and its results in a FAC-014 standard.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. We are extending the implementation time to 24 months based upon the preponderance of comments.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comments.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Oncor supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see response to EEI.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination. That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding. Proposed revision to **FAC-011-4, Part 6.4**: “planned manual load shedding is acceptable only after all available System adjustments have been ***assessed*** (delete made).” Note: SPP was not party to the comment for Question #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. We have considered your suggested rephrasing of FAC-011-4, R6.4. However, our discussion focused on the fact that this evaluation is performed when determining operating plans to mitigate SOL exceedances, and does not preclude an operator, when managing the system, to the take actions they deem necessary to maintain reliability of the system.	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The ISO/RTO Council Standards Review Committee (IRC SRC) supports the changes made by the SDT to FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determination.

That said, the IRC SRC offers the following comment for SDT consideration. While the IRC SRC agrees with the SDT that planned manual load shedding is a last resort, we believe a slight modification to the wording of **FAC-011-4, Part 6.4** is warranted to reflect that planned manual load shedding should only be implemented after all available System adjustments have been assessed and determined that no other available System adjustments can be accomplished in the time available to return the flow within limits without the risk of unplanned load shedding.

Proposed revision to **FAC-011-4, Part 6.4**: "planned manual load shedding is acceptable only after all available System adjustments have been assessed."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. We have considered your suggested rephrasing of FAC-011-4, R6.4. However, our discussion focused on the fact that this evaluation is performed when determining operating plans to mitigate SOL exceedances, and does not preclude an operator, when managing the system, to the take actions they deem necessary to maintain reliability of the system.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to ISO/RTO Counsel (IRC) Standards Review Committee.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	

Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO-NSRF.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
FAC-011-4 contains quite a number of required changes to the RC's SOL Methodology to try to align it more for use with Planning Horizon studies. The changes generally seem appropriate, but questions remain about the details of implementation – have all differences between Planning and Operations been adequately considered? A detailed parsing of each RC's existing SOL Methodology versus a draft modified according to this standard may be needed to fully grasp the potential for issues related to these changes. PG&E has no concerns with the applicable use of TOP-001-6 for SOL exceedance and determinations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The revisions in FAC-011-4 were targeted to improvement of the FAC-011 standard and the RC's SOL methodology and not to alignment with planning horizon studies. The drafting team took into consideration comments from the SDT members, group observers and comments throughout the posting process, with the result being the current proposed FAC-011-4. The SDT has a number of RCs as members, and their comments coupled with those of other RC commenters during the posting process have not	

noted this as a concern. Since the SDT is suggesting an extension of the implementation time to 24 months, all parties should have adequate time to discuss and address any such concern.	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and MISO.	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

No. FAC-014 is administratively burdonsome on small entites by requiring it to accept RC established SOLs without any recourse to address technical problems with the RC established SOLs. It the RC is going to establish and communicate SOLS to a PC or a TP, there should be the ability for the PC or the TP to provide comments and a requirement for the RC to address those comments.

A better approach is discribed in Clark's answer to Question 1. Pay more attention to the changes that are occuring in the west (and maybe elsewhere). The RC is more eficient when dealing with larger entities (BAs, TOPs, and PCs). PCs should be the driving entity for work performed by TPs in the PC footprint. PCs establish the SOL Methodology (using the RC methodology for the Operings Horizon) used by its TPs,and would then consolidate its planning study results with the approved TP planning study results. The PC would then provide the consolidated results to the RC who would in turn provide the approved final SOL list to its TOPs'

Likes 0	
Dislikes 0	
Response	

Thank you for your response. The RC, even in the existing FAC-011 standard, is required to create and SOL methodology, which describes what information will be used as System Operation Limits (SOLs) by all operating entities. As the ultimate operating authority, the RC has the choice as to what information is needed for SOL determination. That information, if it is thermal or voltage limits, are the provided by the

asset owners and not the RC. With regard to stability criteria, the RC, as the ultimate operating authority, has the right to chose what criteria to respect when establishing stability limits. The RC may choose to review and utilize criteria used by operating and planning entities within its footprint, but it is ultimately the RC's decision. Differences in RC and PC thermal or voltage limits, and stability criteria, which were not complimentary would be highlighted by adherence to the SDT's proposed FAC-014-3 R6.	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	
Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please provide further description of the concerns you have regarding implementation of FAC-011-4.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA partially agrees with the SDT revisions that address how SOL exceedances are identified and communicated, but we do not agree with how the definitions of SOL versus SOL exceedances have been confused in FAC-011-4, specifically in Requirement R6 to include a performance framework in the Reliability Coordinator SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses. We request that the SDT reconsider that the constraints that define how SOLs are established are categorically different than how exceedances are defined, identified in the Operations Horizon, and communicated.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Requirement R6 in FAC-011-4 required each RC to include a performance framework within the SOL methodology when determining SOL exceedances. That determination, when made in the Real-time monitoring or Real-time Assessment "windows", would be for actual SOLs exceedances, while when made in the Operational Planning Analysis timeframe, would be for "potential" SOL exceedances. These SOL exceedance determinations are separate and distinct from the System Operating Limits, or SOLs, used in the determination of the existence of an exceedance or not. When communicated between an RC and a TOP, as an example, the SOL exceeded, as well as the SOL exceedance, would be described and discussed. These are two distinct and different things. Requirement R6 concerns using a framework to determine SOL exceedances, and would use SOLs to make those determinations.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our comments to EEI.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT is concerned that the meaning of "communicated" in Requirement R7 is not sufficiently clear. ERCOT suggests that Requirement R7 be revised in order to clarify that communications may be electronic. Similar to the measures accompanying IRO-008, Requirement R5, and TOP-001, Requirement R15, Requirement R7 should be revised to expressly permit electronic communications. Moreover, ERCOT believes "electronic" communications should be defined to include the mere electronic posting of data that enables entities to access/view SOL exceedances. ERCOT further notes that it intends to vote in favor of FAC-011-4, provided Requirement R7 is clarified to provide that communications may be electronic.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement 7 requires the SOL methodology have specific language in it to include a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments. The measure for the requirement has to do with the inclusion of the language, not how the communications of the risk-based SOL exceedances occur. The term "communicated" does not preclude the use of electronic means to accomplish the noted communications.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
FAC-011-4 R7 FAC-011-4 R7 implies the use of a "risk-based" approach for the communication aspects of R7.1.1 through R7.2.2.	

"Risk-based" approach terminology is rare outside of FAC vegetation. As written, this terminology could result in compliance misinterpretation or misunderstanding by operations staff. FAC Standards address the methodology of determining SOLs, COM Standards address the communication protocol between operations, and IRO Standards address interconnected operations of the Bulk Electric System (BES) including coordination with external entities. The SPP Standards Review Group asks the SDT's consideration that R7 should not be a Requirement in the FAC Standards, instead, included with the IRO Standards where it would be intuitive for operations staff to reference. **IRO-008-3 R5** IRO-008-3 R5 provides expectations of operations staff in real-time communication requirements needed to facilitate reliability. This Standard is intentionally, and properly, non-prescriptive in specific aspects of real-time or anticipated SOL risks, and does not introduce "risk-based" prescriptive actions for specific SOL events. The SPP Standards Review Group considers IRO-008-3 R5 sufficient in requiring coordination and communication between entities that take place during SOL and IROL events. If necessary to document SOL methodologies that include the communication and coordination during such events, the SPP Standards Review Group recommends the methodologies should not be more descriptive than IRO-008-3 R5.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The SDT has discussed at length with its members, observers and commenters, the expectation that with the passage of FAC-011-4, and the clarity it will bring to determining SOL exceedances, the number of identified SOL exceedances should increase, and may increase significantly. With this increase, SDT members and observers have all suggested that some means exist to prioritize the SOL exceedances so that the most impactful are communicated expeditiously, while those with less risk wait, and those with their risk eliminated may not be communicated at all (i.e. the ones that "come and go quickly"). The SDT reviewed the existing standards and saw no standard that provided guidance on this subject, which resulted in the creation of FAC-011-4 R7.

Note that IRO-008-2 R5 and R6, as written, would require the communication of each SOL exceedance as it came into existence, and went away. That is why IRO-008-3 R5 and R6 note consistency with the SOL Methodology. FAC-011-4 R7 allows a prioritization of the SOL exceedance communications to focus on the higher impact issues first, and allow a lower risk subset to not be communicated if resolved in a timely fashion.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

Requirement R7 of FAC-011-4 as currently written only provides the ability for a "risk based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated", it does not seem to provide a risk based approach to how SOL exceedances are identified. If the intent is to provide the ability to use a risk based approach to determine how SOL exceedances are identified the language should be modified to make this clear. Requirement R7 could be reworded to say:

"Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances are identified as part of Real-time monitoring and Real-time Assessments and how they must be communicated and if so, the timeframe that communications must occur."

If it is not the intent of the SDT to allow the identification of SOL exceedances to be risk based, requirement R7 may provide some relief from communication requirements that could be burdensome depending on the Reliability Coordinators's SOL methodology, however it does not change that fact that Requirement 6 now makes any post contingent flow projected above a Facilities highest Emergency Rating an SOL exceedance. Some existing SOL methodologies allow for post contingent mitigation actions to be developed within 30 minutes in order to prevent this situation from becoming an SOL exceedance. It does seem appropriate that post contingent flow above the highest emergency rating would be an SOL exceedance, however this would be more stringent than what some have today and require more tracking,

documentation, and communication. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Your concern with regard to the 12 month implementation time is noted, and as a result, the SDT has decided to extend the implementation timeframe to 24 months. The specifics of the example you describe highlight the value of a common framework for SOL exceedance determination that is shared among all operating entities.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
In our opinion a 30 month implementation would be better because an entity may need to purchase new servers, or hardware, and software to meet logging obligations. We are concerned with the burden of providing exceedances due to the level of detail required from our ISO that will also become our responsibility. We believe that a large amount of work will be required to document and log what is expected to be a much larger number of exceedances under the proposed new FAC-011-04 and TOP-001-6 Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While we acknowledge your concerns, the vast majority of commenters offered that the 24 month implementation timeframe seemed adequate, and as such, we are suggesting use of a 24 month implementation plan.	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	

Comment

The Evergy companies do not support the proposed revision to FAC-011-4, TOP-001-6 and IRO-008-3 to address compliance risk and administrative logging.

The revisions are ambiguous and proposed requirements unsustainable.

There is inconsistency between R6.2 and R6.2.1, with the proposed language being confusing.

Moreover, having both Normal Ratings and Emergency Ratings calculated under FAC-008, and, also, entities being required to use both Normal Ratings and Emergency Ratings, is concerning: The revision would require operating at an Emergency Rating for a specified amount of time "*under a no contingency scenario*" rather than the current practice of operating up to an emergency rating indefinitely.

Finally, the Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 2.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. While the SDT may not be able to address all of your comments, your points regarding Normal and Emergency Rating use can be addressed. The language in FAC-011-4 R6.1.1 was based upon lengthy dialogue with SDT members and industry observer participants. Many described the use of Emergency Ratings in their footprints as being based upon what was provided, or requested by the RC or TOP. Many had Emergency Ratings which were time limited in scope (for example, a 4 hour, or 15 minute rating), which may be premised on the use of a limited pre-contingent loading, or the Normal rating. The SDT determined that the use of ratings within FAC-011-4

R6 should allow the use of time limited ratings. If, as in your example, the Emergency Ratings in use in your footprint may be used indefinitely, the language in FAC-011-4 R6 would continue to allow that practice.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes the proposed FAC-011-4 R7 is both too prescriptive and belongs in a TOP standard and Reliability Coordinator procedures developed under IRO-010. IRO-010 requires the Reliability Coordinator to document the information it needs to perform real-time monitoring, and this level of detail would be better left to that documentation. In addition to RC documentation, BPA believes the drafting team's objective of minimizing burdensome notifications can be achieved through the following proposed edit to TOP-001 R15 (bold, italic text added):

R15. Each Transmission Operator shall inform its Reliability Coordinator ***of SOL exceedances determined by its Reliability Coordinator's business procedures to merit notification.***

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The SDT discussed at length what to do with likely increase in SOL exceedances identified with FAC-011-4, and specifically the addition of R6. Many commenters suggested that to communicate all SOL exceedances would be burdensome. Others, including regulatory participants, noted that a failure to communicate regarding important SOL exceedances could adversely impact reliability. The SDT wrote FAC-011-4 R7 with the idea of providing a minimal framework, requiring the most important SOL exceedances to be communicated, while allowing a subset of low risk SOL exceedances to not. The rules to determine how / if the remaining SOL exceedances are to be communicated are left to the RC to determine. We did not feel it wise to not provide some minimal guidance to allow some commonality across the industry for communication of SOL exceedances. The SDT believed failing to do so would invite a FERC requirement to that end, and thought this requirement was the better course of action.

Anthony Jablonski - ReliabilityFirst - 10

Answer	No
Document Name	
Comment	

ReliabilityFirst offers the following comments on FAC-011-4 for the SDT's consideration. In the clean version of FAC-011-4, in the "New or Modified Term(s) Used in NERC Reliability Standards" section of the Standard, it states: "None." The term "System Operating Limit" has been modified and "System Voltage Limit" is newly defined.

Requirement R6 part 6.1.4, part 6.2.4, and part 6.3 references: "Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." What is the meaning of "that adversely impact the reliability of the Bulk Electric System does not occur?" Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? These parts of Requirement R6 are open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term "… that adversely impact the reliability of the Bulk Electric System."

Requirement R7 does not specify which entities (TOPs? BAs? DPs?, etc.) are to be the receivers of the referenced communications of SOL exceedances. The "timeframe that communications must occur" are left to the discretion of the RC. The Requirement should be revised to clarify which entities the RC must communicate SOL exceedances to, and to specify a timeframe for the communication (of SOL exceedances) to occur.

FAC-011-4 requires the RC to have a SOL methodology and to provide the methodology to other entities (including TOPs within the RC area). TOPs are required (per FAC-014) to establish SOLs consistent with the RC's SOL methodology. The RC's SOL methodology typically specifies that the model to be used covers the entire RC footprint, as well as at least portions of adjacent RC's footprints. TOPs should not be required to follow an RC's SOL methodology to include a model that covers the entire RC (and portions of adjacent RC's) footprint. TOPs don't typically have models this large.

Likes 0	

Dislikes 0	
Response	

Thank you for your comments. In the final posting, we will note the new and revised definitions. Those were not changed for this posting, so we believe the notation was correct.

With regard to your comments on Requirement 6.1.4, 6.2.4 and 6.3, the phrase you note was taken from the definition of an IROL. The SDT has noted during is discussions on FAC-011 that entities seemed to have differing definitions for what constitutes an IROL. As such, the SDT chose instead to use the definition for the term, since it was viewed as more specific. Having said that, the SDT tried but could not arrive at a revised definition for IROL that was less open to interpretation; that effort is to be undertaken by a later SDT. The SDT believes the language is an improvement and was carefully vetted.

Your comment regarding R7 is correct; the standard does not include any identified entities for receipt of the information. It instead requires the RC to document how SOL exceedances will be communicated in their SOL methodology. The SDT recognizes that the IRO and TOP standards, and specifically TOP-001 and IRO-008, speak to communication between TOPs and RCs regarding SOL exceedances. The SDT wrote FAC-011-4 R7 with those two standards, and the required SOL exceedance communications, in mind.

With regard to your last point, FAC-011-4, R4.5 speaks to the level of “detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits”. The standard is silent with regard to the level of modeling required to identify thermal and voltage constraints / exceedances. The SDT believes this is a matter to be determined by the RC and its TOPs.

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	
Comment	

LES feels that the sub-requirements listed in R7 may cause confusion as they relate to the performance criteria of R6. Suggest changing the word "of" to "based on", which will allow for a distinct correlation between what is and isn't a SOL exceedance. For example, 7.1.4 could be read as an independent check against Facility Ratings, which would raise the question whether it relates to Normal or Emergency Ratings. SOL exceedances should only be declared based on the performance criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We will take your suggestion under consideration. It should be noted that R7 was written such that use of the framework shown in R6 would be the basis for determining the various categories of SOL exceedances noted in the sub-requirements of R7. The one you note, for example, was left general using the phrase "of Facility Ratings" so that the RC could choose, based upon current or preferred practice, where exceedances of Normal or Emergency Ratings would be included in this category.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to Mr. Allen's comments.	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No

Document Name	
Comment	

Besides the concerns expressed in response to question 1, what is the purpose of communicating SOL exceedances to the Reliability Coordinator? If the purpose is for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then the data specification concept is a more effective and efficient method and should be maintained in IRO-010-2 where each Reliability Coordinator has the flexibility to determine the items that need reported, the method and a timeframe based on their individual operating environment. Having this requirement detached in FAC-011 could lead to misunderstanding of context, expectations and/or compliance failures, which is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distract our operations personnel and doesn't benefit reliability.

R7.2.2. Please explain the rationale for 30 minutes for this one specific item when (according to R6.1 and further explained in the System Operating Limit Definition and Exceedance Clarification whitepaper) pre-contingency exceedances of much shorter timeframes are an indication of unacceptable system performance? This requirement seems to imply the risk of high voltage is minimal for all registered entities and their equipment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. TOP-001 and IRO-008 already have requirements for the TOP to communicate actions used to mitigate SOL exceedances to the RC (R15) and for RC to communicate to TOPs when they identify (R5) or see mitigate / prevented (R6) an SOL exceedance. The versions of these requirements proposed in TOP-001-6 and IRO-008-3 use the FACA-011-4 R7 construct to inform which SOL exceedance communicates must occur, and which ones need not. It would further be used if the RC requested other forms of SOL exceedance communication, due to IRO-010, as you note.

With regard to your question on R7.2.2, the 30 minute timeframe was introduced after SDT discussion of experiences of both SDT members and observers with regard potential durations of pre-contingency high voltage conditions and post-contingency exceedances of thermal

limits, and what timeframe would be reasonable to not cause a high number of nuisance notifications. Note this requirement sets a floor, which can be changed by an RC when establishing this risk-based SOL exceedance communication protocol.	
Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	Yes
Document Name	Project 2015-09_SOLs Comment_Form-Final.docx
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT's intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits."

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT's intent is correct):

FAC-011-4, 7.1.4 “Facility Ratings as described in Part 6.1.1”

FAC-011-4, 7.2.1 “Facility Ratings as described in Part 6.2.1”

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 “Pre-contingency SOL exceedances of Facility Ratings; and”

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true):

FAC-011-4, 7.2.1 “Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and“

7.2.2. Post-contingency SOL exceedances of emergency System Voltage Limits;

7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits

Likes 0	
Dislikes 0	

Response

Thank you for your comments. With regard to your first comment, the SDT agrees that the thermal SOL exceedances refer to steady or constant exceedances and not transient or temporary ones. That is one of the reasons that the phrase “steady state” was added to Requirements parts 6.1.1, 6.1.2, 6.2.1 and 6.2.2. The SDT has often, when discussing SOL exceedances, especially post-contingent identified ones, noted that good practice would normally expect more than one real time contingency analysis to be used to confirm existence of the SOL exceedance. Doing so should eliminate momentary errors or short-term excursions from consideration as SOL exceedances.

With regard to your proposed language changes for FAC-011-4, Requirement 7 and its subparts, the SDT respectfully suggests that with the descriptive language used in FAC-011-4, Requirement 6 and its subparts, there should be no confusion on where voltage will cause an SOL exceedance when considering low or high System Voltage Limits. The term “within” is used both in FAC-011-4 Requirement subparts 6.1.2 and 6.2.2, noting that being “within” the limits is acceptable. The use and understanding of this term in FAC-011-4, Requirement 6 should then allow consistent interpretation of FAC-011-4, Requirement 7 and its subparts dealing with SOL voltage exceedances, namely Parts 7.1.5, 7.2.1 and 7.2.2.

With respect to the suggested use of the phrase "as described in . . . ", the SDT was deliberate in its word choice in Parts 7.1.4 and 7.2.1. The words choice for Part 7.1.4, that of "Pre-contingency SOL exceedances of Facility Ratings", provides some flexibility such that depending on how the RC has implemented their pre-contingency Facility Rating SOL exceedance monitoring, the corresponding attribution to meet Part 7.1.4 could be matched. The same flexibility holds true with the wording choice on Part 7.2.1.

Having said that, the other revision suggested, removing the word "and" in Parts 7.1.4 and 7.2.2 does not impact the intended meaning and, as noted, removes a potential source of confusion. The SDT will make this revision.

Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
Generally, PG&E has no objections to the revisions, but has some concerns with implementation for FAC-011-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please feel free to share your specific concerns with the SDT.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	

Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our responses to the MRO comments.	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the IRC SRC.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
MISO supports the comments filed by the IRC SRC.	

The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance. In addition, the IRC SRC requests the SDT consider implementing the following clarifications: Proposed Language (if our interpretation of the SDT's intent is correct): **FAC-011-4, 7.1.4** "Facility Ratings as described in Part 6.1.1" **FAC-011-4, 7.2.1** "Facility Ratings as described in Part 6.2.1" Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true): **FAC-011-4, 7.1.4** "Pre-contingency SOL exceedances of Facility Ratings;" Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true): **FAC-011-4, 7.2.1** Post-contingency SOL exceedances of Facility Ratings; **7.2.2**. Post-contingency SOL exceedances of emergency System Voltage Limits; **7.2.3.** Pre-contingency SOL exceedances of normal high System Voltage Limits	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. With regard to your first comment, the SDT agrees that the thermal SOL exceedances refer to steady or constant exceedances and not transient or temporary ones. That is one of the reasons that the phrase “steady state” was added to Requirements parts 6.1.1, 6.1.2, 6.2.1 and 6.2.2. The SDT has often, when discussing SOL exceedances, especially post-contingent identified ones, noted that good practice would normally expect more than one real time contingency analysis to be used to confirm existence of the SOL exceedance. Doing so should eliminate momentary errors or short-term excursions from consideration as SOL exceedances. With regard to your proposed language changes for FAC-011-4, Requirement 7 and its subparts, the SDT respectfully suggests that with the descriptive language used in FAC-011-4, Requirement 6 and its subparts, there should be no confusion on where voltage will cause an SOL exceedance when considering low or high System Voltage Limits. The term “within” is used both in FAC-011-4 Requirement subparts 6.1.2 and 6.2.2, noting that being “within” the limits is acceptable. The use and understanding of this term in FAC-011-4, Requirement 6 should then allow consistent interpretation of FAC-011-4, Requirement 7 and its subparts dealing with SOL voltage exceedances, namely Parts 7.1.5, 7.2.1 and 7.2.2. With respect to the suggested use of the phrase “as described in . . . “, the SDT was deliberate in its word choice in Parts 7.1.4 and 7.2.1. The words choice for Part 7.1.4, that of “Pre-contingency SOL exceedances of Facility Ratings”, provides some flexibility such that depending on how the RC has implemented their pre-contingency Facility Rating SOL exceedance monitoring, the corresponding attribution to meet Part 7.1.4 could be matched. The same flexibility holds true with the wording choice on Part 7.2.1. Having said that, the other revision suggested, removing the word “and” in Parts 7.1.4 and 7.2.2 does not impact the intended meaning and, as noted, removes a potential source of confusion. The SDT will make this revision.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The IRC SRC agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, the IRC SRC requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will occur and be dispositioned in	

accordance with the RC's SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance. In addition, the IRC SRC requests the SDT consider implementing the following clarifications: Proposed Language (if our interpretation of the SDT's intent is correct): **FAC-011-4, 7.1.4** "Facility Ratings ***as described in Part 6.1.1***" **FAC-011-4, 7.2.1** "Facility Ratings ***as described in Part 6.2.1***" Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 and 7.1.5 need to be true by removing the word 'and'): **FAC-011-4, 7.1.4** "Pre-contingency SOL exceedances of Facility Ratings; ***(delete and)***" Proposed Language (to eliminate potential interpretation that use of the word "and" indicates both parts need to be true): **FAC-011-4, 7.2.1** "Post-contingency SOL exceedances of Facility Ratings***;(Delete - and emergency System Voltage limits, and)"*** **7.2.2**. ***Post-contingency SOL exceedances of*** emergency System Voltage Limits; ***7.2.3.*** Pre-contingency SOL exceedances of normal high System Voltage Limits	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Due to the similarities in your comments, please see our response to MISO.	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to EEI.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL feels the industry needs more time with the implementation schedule to address coordination adjustments between RCs & TOPs to integrate the revisions of the RC's SOL methodology based on the updated framework. This could involve monitoring and system updates for efficient data transfers (automatic logging and reporting) to make these additional reporting requirements manageable for System Operators and Compliance Staff, and of course keeping the compliance records between the TOP and RC in lock-step. The implementation plan document states that the "TOP-001-6" and "IRO-008-3" versions will be retired. IPL believes these are typos (meant to list the older versions of TOP-001-5/IRO-008-2), the SDT will need to revise this document to provide the plan for TOP-001-6 and IRO-008-3.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The SDT has chosen to extend the implementation time period to 24 months. We will review the noted "typos" and correct as needed.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees with your concern and based on the feedback of you and others, has decided to extend the implementation time period to 24 months.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
No Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes, however; this does not fully address Southern Company's specific concerns noted in Question 1 on the requirement revisions related to the establishment of limits, contingency events, and performance framework in FAC-011-4.	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Thank you for your comments. The SDT has responded where you provided specific comments and concerns regarding FAC-011-4. If you have further concerns, please address them to the SDT.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6	

Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to EEI.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy supports the following comments provided by EEI: *EEI supports the inclusion of Requirement R7, which provides the industry with a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. However, the implementation timeframe should be increased to allow for the increased burden of both identifying and validating exceedances. The SDT should modify the implementation plan to provide at least 24 months to allow the industry to address the proposed changes.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your concern and based on the feedback of you and others, has decided to extend the implementation time period to 24 months.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your concern and based on the feedback of you and others, has decided to extend the implementation time period to 24 months.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Please consider a 24 calendar month implementation plan, instead of 12 calendar months. Additional tracking, validation, and documentation of exceedances will be necessary. Enhancements to existing tracking tools may be required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your concern and based on the feedback of you and others, has decided to extend the implementation time period to 24 months.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	

ATC believes the existing language of R7 may be adequate. However, we think some additional clarity on two specific requirements (R7.1.4 and R7.2.1) would benefit the industry. Both items relate back to how FAC-011-4 Requirement 7 does or does not tie back to the language of Requirement 6. In these two requirements, the clarification requested is, which Facility Ratings are in view as explained below.

New Requirement R7.1.4 states, “Pre-contingency SOL exceedances of Facility Ratings”. Based on our reading of the draft standard, we believe the SDT is referring to the thermal Facility Ratings described in requirement R6.1.1 (i.e. Normal and Emergency Ratings). R6.1.1 reads, “Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.”

Similarly, requirement R7.2.1 reads, “Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits”. We believe the SDT intends for “Facility Ratings” to correspond to the Facility Ratings described in R6.2.1 (“Steady State post-Contingency flow through Facilities are within applicable Emergency Ratings., provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating.”)

Regardless as to whether or not ATC’s interpretation is correct, we believe the industry will benefit in the future from greater clarity. For example, if ATC’s interpretation is correct, the SDT could add wording such as, “Facility Ratings as described in R6.1.1” for R7.1.4 and “Facility Ratings as described in R6.2.1” for R7.2.1.

ATC also has one minor comment on the formatting of R7.1 and R7.2 requirements. The word “and” appears in different sub-requirements, as shown below. We request the SDT review if “and” is correct wording to use, since a reader may interpret that all these items may need to be simultaneously true before the threshold is reached for communicating. The clearest example is R7.2.1. ATC believes that removing “and” and splitting up R7.2.1 as follows may be beneficial:

7.1.4. Pre-contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-contingency SOL exceedances of normal low System Voltage Limits.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and 7.2.2 Post-contingency SOL exceedances of emergency System Voltage limits, and 7.2.3. Pre-contingency SOL exceedances of normal high System Voltage Limits.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Due to the similarities in your comments, please see our response to MISO, which we believe addresses your concerns.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the MRO.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

1. The construct in the proposed FAC-0114 (and Requirement R6) maintains how System Operators generally define IROLs today, and the long-standing operating practice where the loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.

The IESO suggests that the footnote to Requirement R6, sub-requirement 6.2.4 be expanded to include this industry practice, as follows:

Sub-requirement R 6.2.4:

" Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur"[Footnote 1}

[Footnote 1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques. *Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining bulk power system.*

2. The IESO seek clarification as to what is meant by *"expected to produce more severe System impacts"* in R4 Sub-requirement 4.2?

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. With regard to your requested clarification on the footnote to Requirement R6, sub-requirement 6.2.4, the SDT believes that while that practice may be common, and explicit in use in some regions, it is not universal, and as such, should not be placed in the footnote. With regard to the clarification sought on the meaning of "expected to produce more severe System impacts" in R4 Sub-requirement 4.2, this phrasing was include to allow those performing stability studies to focus on the subset of all potential stability contingencies / simulations which should produce the most limiting performance. Prior commenters noted that without such language, Requirement R4, and its sub requirements, could be interpreted to mean that all potential contingencies be tested in stability. The SDT recognized industry practices and the listed concern, and added this language as a result.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the NSRF.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
MEC supports MRO NSRF comments. The MRO NSRF agrees with the changes proposed by the SDT to FAC-011-4, TOP-001-6 and IRO-008-3. That said, MISO requests the SDT acknowledge that momentary errors or other specified short-term excursions above Emergency Limits will	

occur and be dispositioned in accordance with the RC’s SOL methodology. We would like to see this clarification in either the measures in the standard, the RSAW or Compliance Guidance

In addition, MRO NSRF requests the SDT consider implementing the clarifications below. Note that each request is presented independently for ease of review; however, when viewed collectively, there some requirements which would benefit from multiple clarifications that are additive:

Proposed Language (to clarify the description, if our interpretation of the SDT’s intent is correct):

FAC-011-4, R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOLs exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses

Proposed Language (to clarify what is intended; as currently written, exceeding the normal low System Voltage Limit could be interpreted as operating at a higher voltage than the minimum [i.e. exceeding the limit] which would not necessarily have adverse impacts unless the operating voltage was also exceeding the high System Voltage Limit):

FAC-011-4, R7.1.5. Pre-contingency operating conditions outside SOL exceedances of normal low System Voltage Limits.”

FAC-011-4, R7.2.1. Post-contingency operating conditions outside SOL exceedances of Facility Ratings and emergency System Voltage limits, and

Proposed Language (to add clarity by adding a reference to the corresponding description under FAC-011, requirement R6, if our interpretation of the SDT’s intent is correct):

FAC-011-4, 7.1.4 “Facility Ratings as described in Part 6.1.1”

FAC-011-4, 7.2.1 “Facility Ratings as described in Part 6.2.1”

Proposed Language (to eliminate the potential interpretation that both parts 7.1.4 *and* 7.1.5 need to be true before the communication threshold is reached):

FAC-011-4, 7.1.4 “Pre-contingency SOL exceedances of Facility Ratings; and”

Proposed Language (to eliminate potential interpretation that use of the word “and” indicates both parts need to be true): **FAC-011-4, 7.2.1** “Post-contingency SOL exceedances of Facility Ratings; and emergency System Voltage limits, and“ **7.2.2**. Post-contingency SOL exceedances of emergency System Voltage Limits; **7.2.3.** Pre-contingency SOL exceedances of normal high System Voltage Limits	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to the MRO NSRF.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see our response to the MRO NSRF.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Comment	
Duke Energy agrees with the revisions but due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implemenation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based upon industry feedback, we plan on extending the implementation period to 24 months.	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following recommendations regarding communication as described in proposed FAC-011-4 Requirement R7.

- Specify to whom the SOL exceedances must be communicated.
- Add language to specify that communication of SOL exceedances includes prevention and mitigation (IRO-008-3 R6) and actions taken to return the System to within limits when a SOL has been exceeded (TOP-001-6 R15). Even if Part 7.1 SOL exceedance is mitigated within timeframes identified for communication of SOL exceedances, this information should be communicated.
- Add language to communicate post-Contingency SOL exceedances of “normal minimum System Voltage Limits” or “normal maximum System Voltage Limits”. An exceedance could occur for an extended amount of time with no communication which may jeopardize the reliability of the System when the next Contingency occurs.
- Specify the time duration for IROL exceedances to be communicated in Part 7.1.1. The NERC Glossary definition states that IROL Tv should not exceed 30 minutes. Texas RE recommends the SDT consider adding language that the RC should communicate IROL exceedances within 30 minutes rather than its discretion.
- Remove “Outages” after “Cascading” in Part 7.1.3 since “Cascading Outages” is not a defined term per the NERC Glossary.
- Capitalize “contingency” in Part 7.1.3 wherever used since it is a defined term in the NERC Glossary. This includes “pre-“ and “post-“ usages.
- Include a description of what “validated risk” in Part 7.1.3 means or when the risk should be validated. The case could exist where there could be “post-contingency SOL exceedances” identified but there is no defined duration (time period) for an RC to “validate” the risk. An RC could take hours to validate that a contingency could occur that violated an Emergency Rating (time duration in minutes perhaps) and not communicate that issue in a timeframe that supports reliable operations (and 7.2 does not alleviate the concern.)

Additionally, Texas RE inquires as to whether a post-contingency operating state is identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation, but it is determined the instability, Cascading or uncontrolled separation that adversely impact the

reliability of the Bulk Electric System, would this be required to be identified and communicated since it may not be an SOL exceedance per Part 6.4? • Use the terms “normal minimum” and “normal high” in Part 7.1.5 to be consistent with the proposed definition of System Voltage Limit. • Specify a timeframe for the RC to communicate SOL exceedances that are not resolved within 30 minutes in Parts 7.1 and 7.2. If the SOL exceedance is not communicated timely, multiple entities could be working to mitigate the issue and the actions could potentially conflict with each other. Affected entities should be coordinating so they know what is being done and will not affect each other. They should confirm what each is doing to mitigate the SOL exceedance. For example, the RC could be taking certain measures at the same time an LCC is taking different measures. If they are not communicating, this could lead to adverse effects. • Capitalize “limits” in Part 7.1.2 since it is part of the proposed term System Voltage Limits.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The typos / capitalization revisions / definition wording concerns noted will be reviewed and corrected as needed; thank you for pointing those out. The SDT did not include in FAC-011-4 R7 which entities need communication of SOL exceedances because we wished to leave it to the remaining standards to specify, at a minimum, when those communications need to occur. The three instances where we see requirements for SOL exceedance communication are in TOP-001-6, R15, and IRO-008-3, R5 and R6. Should future standards require more SOL exceedance communication, or the RC require more itself, we thought that FAC-011-4 R7 should be written to work seamlessly in either instance. With regard to your second bulleted item, the SDT included the specific language in FAC-011-4, R7.2 so that a subset of lower risk SOL exceedances need not be communicated if resolved within 30 minutes. This language was arrived at after discussing the implications of adopting of R6 in FAC-011-4, the likely increase in identified SOL exceedances in industry, the requirement that operating entities perform	

real time contingency analysis only every 30 minutes (and hence confirmation of the continued existing of an SOL exceedance would only occur with its 2nd RTCA identification), and the interest in only taking the time to discuss those SOL exceedances that either persist or have a high enough risk profile that warrant an earlier discussion.

The SDT tried to walk a careful line between not being too prescriptive and not being prescriptive enough. The categories of SOL exceedances we felt should be definitely communicated were IROLs and ones that had a decent chance to evolve into IROLs. The ones which we believed did not need to be communicated were low risk SOL exceedances which were resolved with a reasonable level of expediency (less than 30 minutes). While that leaves a wide range of SOL exceedances with no specification, the SDT felt that it was appropriate for the RC to determine, based on existing practice, understanding the impact of the new FAC-011-4, and specifically R6, and discussion with their stakeholders (primarily their TOPs), what level of communication supports the reliable operation of the system without presenting a burden on the operator which would detract from operating the system. As such, we do not think the suggested addition of other SOL exceedance categories should be done through this requirement, but instead should be considered for local adoption if reasonable and of value.

The SDT did not think it was necessary to introduce a communication timeframe for IROL exceedances. We recognize these need resolution within the appropriate timeframe, which does not exceed 30 minutes, and entities need to communicate those IROL exceedances well within 30 minutes to successfully mitigate those exceedances. Similarly, we did not think it was wise to specify a timeframe for SOL exceedance communication in FAC-011-4 R7, parts 7.1 and 7.2. The SDT reasoned that the RC and its TOPs should determine the appropriate time for their unique circumstances.

Thank you for pointing out the language issues in Part 7.1.5. The SDT will revise this standard and use the “minimum” and “maximum” terms found in the definition of System Voltage Limits.

The SDT did discuss at length what is a “validated risk”. The SDT agreed that this is commonly a manual confirmation of an RTCA result, which would preclude transient results of erroneous state estimator results from causing incorrect SOL exceedance identification. We did not think this term required definition, but will include this discussion in the rationale.

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri – 4	
Answer	
Document Name	
Comment	
The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?	
Likes 0	
Dislikes 0	
Response	
The phrase "that adversely impact the reliability of the Bulk Electric System" is being used under the NERC currently approved definition of IROL, as such the phrase was added in the FAC-011 requirements. The Reliability Coordinator in its SOL methodology is required to have a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. – 6	
Answer	
Document Name	
Comment	

NIPSCO believes the Implementation Plan Effective Date is short and should be increased from twelve (12) calendar months to **thirty-six (36) calendar months.** We will work with the **EMS** vendor to create a process for related logging. In addition to developing new processes, related **training** will need to be developed and delivered. Furthermore, MISO will develop and implement new **methodology** and protocols. **This will all require additional time.**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. After considering all the industry comment, the implementation plan has been extended to 24 months.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to John Allen’s comment.	
Bruce Reimer - Manitoba Hydro – 1	
Answer	

Document Name	
Comment	
The changes to these standards place a considerable reporting requirement on SOL exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal 12 months implementation period to work out SOL reporting methodology with the RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. After considering all the industry comment, the implementation plan has been extended to 24 months.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
“These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments”. Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project. **1. Extend the implementation timeframe** - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line	

ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations.

Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months.

For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

2. Coordinate common SOLs - The MRO NSRF respectfully requests the SDT to consider coordination of all common SOLs similar to what is proposed in **FAC-011-4, Part 3.5** which requires the SOL methodology to define the method for determining common System Voltage Limits between the RC and its TOPs, between adjacent TOPs, and between adjacent RCs within an interconnection.

3. Replace IROL language with "Adverse Reliability Impact" - The MRO NSRF respectfully requests the SDT replace language excerpted from the current IROL definition with the current definition of "Adverse Reliablity Impact" to indicate that no amount of instability, Cascading or uncontrolled separation is acceptable:

Proposed Language

FAC-011-4, Parts 6.1.4 and 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur.

Footnote 1, page 5: Stability evaluations and assessments of instability, Cascading, and uncontrolled separation Adverse Reliability Impacts can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques

FAC-011-4, Part 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System Adverse Reliability Impacts does not occur

FAC-011-4, Part 7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation Adverse Reliability Impacts

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

1. After considering all the industry comment, the implementation plan has been extended to 24 months.
2. The SDT has made the changes in R3.5 to include the suggested change
3. The SDT has made the changes in Part 6.1.4 and 6.2.4 as well as in Part 6.3

Richard Jackson - U.S. Bureau of Reclamation – 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	
Document Name	

Comment

R4.6: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale.

R4.7: Please clarify. Consider adding language to clarify the intent of this requirement as stated in the rationale. Consider adding "for post-contingency mitigation" are not allowed....

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has considered your comment and decided to not make any change in the requirement R4.6 and R4.7

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro agrees with the proposed FAC-011-4 R6 provides clarity on SOL exceedances that may alleviate the need for a glossary definition and offers the following comments and suggestions:

FAC-011-4 R6.2.1

The addition of “Steady state-post-Contingency flow through a Facility must not be above the Facility’s highest Emergency Rating” to “Steady State post-Contingency flow through Facilities within applicable Emergency Ratings” in Requirement 6.2.1 appears redundant and can possibly create confusion.

Please consider the following wording:

“Steady state-post-Contingency flow through a Facility must not be above the Facility’s highest *applicable* Emergency Rating”

Rationale for "applicable" is to reflect that Emergency Ratings must also observe the time duration requirement in the RC's SOL Methodology, and also that the highest Emergency rating can change seasonally. The currently proposed language in requirements R6.2.1 and R6.2.2 appears to imply a more nuanced post-contingency performance requirement for flow vs. voltage. As requirements R6.2.1 and R6.2.2 are conceptually the same, so BC Hydro suggest that the use of similar wording. FAC-011-3 R3.4 "Identify the lowest allowable System Voltage Limit" If RC is required to identify a specific low voltage limit across its entire RC area, this will likely be a theoretical limit, which may not address the reliability issues that exist in specific areas of the RC Area. Rather than prescribing a specific limit applicable across the system, a list of qualitative considerations for establishing voltage stability based SOLs could be included instead. These considerations may include under voltage load shedding schemes design, voltage instability, loss of synchronism etc), and other prescriptions in support of accurate modeling of post contingency powerflow (e.g. low voltage limit not lower than value that could cause load trip due to process controls or motor contactors dropping etc.).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made the change in R6.2.1 and R6.2.2 With regards to R3.4, the rationale is to ensure that there is consistency of lowest System Voltage Limit across the RC area. For example, an RC may not allow System Voltage Limit to be set lower than an existing Under Voltage Load Shedding (UVLS).	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. – 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. – 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments. Please note that the NSRF has concerns that if the Implementation Plan is not adjusted to atleast 24 months that this may impact our Final Ballot of the Standards within this Project.months that this may impact our Final Ballot of the Standards within this Project. **1. Extend the implementation timeframe** - The MRO NSRF respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile what is expected to be a significantly larger number of documented SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). To support this change, it is anticipated that companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools in order to accurately track and validate SOL exceedances. While many entities may already utilize these same tools to identify and track SOL exceedances, most will have to further enhance these tools if they use dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations. Aside from tools, implementation of the new standards will also require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, MRO NSRF is requesting the SDT consider extending the implementation timeframe to at least 24 months. For this approach to be successful, the effective dates of FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 need to be synchronized so they coincide.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Please see respond to MRO NSRF Comments.

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see respond to MRO NSRF Comments.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	

Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	

In addition to the specific concerns noted in Question 1, Southern Company offers the following comments on the SOL exceedance determination, use, and communications in FAC-011-4:

1) Requirement 6.4 of FAC-011-4 should have additional clarity that the limitation on manual load shedding only refers to firm load consistent with FERC Order 693. Specifically, the following changes should be made

6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual **FIRM** load shedding is acceptable only after all other available System adjustments have been made.

2) Additionally, the SOL whitepaper, of which the implementation of FAC-011-4 is largely based, appears to mistakenly refer to TOP-001-3 instead of TOP-001-6 on page 6

3) Lastly, the NERC timehorizon and the SOL whitepaper should add an additional time horizon of "Day-Ahead Operations" that can be used to clearly delineate the horizon in which SOLs are established and applicable in FAC-011-4. Ideally, Operations Planning horizon would be slightly modified to prevent overlap, but as this may impact other standards, it would be acceptable to leave more broad if necessary. Specifically, the new horizon would be termed "Day-Ahead Operations – operating and resource plans within the day-ahead timeframe" and replace the Operations Planning Horizon applicability of R5 through R9.

Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	

Thank you for your comment. With regards to R6.4 and SOL whitepaper, the SDT has add more clarity in the rationale. With regards to R5 through R9 has time horizon is classified as Operations Planning that include Day-Ahead Operations	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	
Document Name	
Comment	
OGE supports MRO-NSRF's recommendation to extend the timeframe for implementation from 12 to 24 calendar months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see respond to MRO NSRF Comments.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see respond to MRO NSRF Comments.

LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	
Document Name	
Comment	

ATC supports the changes proposed for the FAC-011, FAC-014, IRO-008 and TOP-001 standards. However, the 12 month implementation timeframe should be extended to 30 months. This additional time is needed to allow for the following sequential actions:

First, the RC will need to update its methodology (in the case of MISO, this will be through a stakeholder process).

Second, the TOP will need to update its operating practices and procedures to follow the revised RC methodology.

Finally, likely in parallel, the RC and TOP will need train staff to adhere to the new requirements and methodology and create new processes to ensure documentation is developed, either automatically or manually, as new SOL exceedances are managed as evidence of compliance.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. After considering industry comment, the implementation plan has been extended to 24 months.

Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	
Document Name	
Comment	

Some industry stakeholders believe the implementation plan should be 18 months as opposed to 12 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. After considering industry comment, the implementation plan has been extended to 24 months.	
Mark Holman - PJM Interconnection, L.L.C. – 2	
Answer	
Document Name	
Comment	

R4.2 A portion of the redline language, “*applicable to the establishment of stability limits*” is redundant to the language that starts the requirement. The existing language “*to meet the criteria specified in Part 4.1*” already addresses the “that are expected to produce more severe System impacts”. Only focusing on “*its portion of the BES*” could permit an RC or TOP to ignore addressing impacts to their neighboring TOP/RC, and as such should be expanded or dropped.

Given the intent is to indicate that not all the contingencies captured within R5 are applicable and/or required in order to establish stability limits, the following suggested language mirrors similar clarifying contingency language proposed by the SDT for FAC-011-4 R6.3:

Proposed Language: *Require that stability limits are established to meet the criteria specified in Part 4.1 for applicable Contingencies identified in Requirement R5.*

R6.2.4 Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

Given that 6.2.4 is applicable only to System performance *following contingencies*, suggest that "does not" be replace with "would not". · **Proposed Language:** *Instability, Cascading or uncontrolled separation that adversely impact the reliability of the BES would not occur.* **R7** The proposed language in R7 does not solely provide, as the rationale states, "a performance framework for determining SOL exceedances in the RC's SOL methodology." Rather, it provided a communication framework around those SOL exceedances deemed reportable. However, R7 does not indicate any requirement around the communication (from whom & to whom) beyond it being directed to take place by the RC's methodology, which could include an RC communicating internally to itself. The proposed language below proscribes a direction of communication. If the SDT would prefer the RC's methodology to spell out the communication path, then that need should be included in a sub-requirement of R7. · **Proposed Language:** *Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining which SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated by the Transmission Operator or the Reliability Coordinator to impacted Transmission Operators or Reliability Coordinators, and if so, the timeframe that communications must occur. The approach shall include:*

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT has considered your comment regarding R4.2 and R.6.2.4 and made no additional change. With regards to R7, the requirement does not include any identified entities for receipt of the SOL exceedance information. It instead requires the RC to document how SOL exceedances will be communicated in their SOL methodology. The SDT recognizes that the IRO and TOP standards, and specifically TOP-001 and IRO-008, speak to communication between TOPs and RCs regarding SOL exceedances. The SDT wrote FAC-011-4 R7 with those two standards, and the required SOL exceedance communications, in mind. This construct allows flexibility, should future standards require additional SOL exceedance communication.
Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer	
Document Name	
Comment	

Texas RE has the following additional comments for proposed FAC-011-4:

- Stability is a defined term in the NERC Glossary, but is used throughout FAC-011 (e.g. stability limits, stability performance, steady-state voltage stability, angular stability) and is not capitalized. Texas RE recommends the SDT take steps to incorporate the defined term into the Standards, update the definition, or retire the definition as appropriate.

- The language of Requirement R2 could imply that the RC owns Facilities, which is not typical.

- Texas RE recommends revising Requirement R2 to match the language in the rationale. It should be revised to "…such that the Transmission Operator**s** and **their** Reliability Coordinator**(s)** use common Facility Ratings."

- Requirement R3.1 shows System Voltage Limit(s) as both singular and plural.   Please review for correct grammar.

- Texas RE recommends including a minimum bar for stability performance criteria in Requirement R4. As written, the RC has unlimited discretion to determine performance criteria that is used to establish stability limits, which can lead to action not being taken unless there is an Emergency.

- Texas RE is concerned with the vague language in Part 4.2. The current language indicates an entity will be expected to clearly demonstrate how stability limits are "expected" to produce more "severe" System impacts, but there is no threshold provided for what "severe" is. This language could result in an entity indicating all impacts are the same and there are no stability limits needed.

- In Part 4.3, Texas RE recommends the SDT consider adding "or other Reliability Coordinators Areas within its Interconnection" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections. Part 4.5 is similar: "other Reliability Coordinator Areas within its Interconnection."

- Part 5.3 only requires the RC to "[d]escribe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits." Texas RE recommends including language within FAC-011 or FAC-014 to require the RC to provide justification when Contingency events provided per FAC-014-3 R7 are not used in determining stability limits.

- Texas RE noticed there is no discussion of thermal limits in FAC-011. Does the SDT agree that thermal Facility Ratings are thermal SOLs?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

- The SDT discussed the potential usage of the NERC defined term Stability. The items listed under FAC-011 are intentionally put as stability performance, steady-state voltage stability, angular stability because they are different than the Stability term as defined in the NERC glossary of terms.
- The language of Requirement R2 states that Facility Ratings are owner-provided, no changes are made in R2.
- Requirement R3.1 has been updated for correct grammar.
- The SDT discussed that RC areas may contain multiple Planning Coordinator (PC) areas. Which may have different criteria for planning requirements when it comes to stability performance criteria, including any margins applied. As a result, the RC is given the flexibility to set the criteria. No modification is done for R4.1.
- Part 4.2. has been updated to utilize and match the language also used in the NERC TPL standards.
- Part 4.3 has been modified to add "or other Reliability Coordinators Areas". Please note that stability limit on back-to-back HVDC line between two Interconnections need to be coordinated. The limit will need to take into account the system performance in both Interconnections.

- The SDT discussed Texas RE's recommendation to require RC to provide justification when Contingency events provided per FAC-014-3 R7 are not used in determining stability limits. The SDT believes that this is not necessary and no requirements were modified for this purpose.
- The SDT agree that thermal Facility Ratings are SOLs

Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	
Document Name	
Comment	
Requirement 6 lists language stating "that adversely impact the reliability of the BES" without detailing what is considered "adverse impact." This introduces inconsistences among the industry.	
Likes 0	
Dislikes 0	
Response	
The phrase "that adversely impact the reliability of the Bulk Electric System" is being used under the NERC currently approved definition of IROL, as such the phrase was added in the FAC-011 requirements. The Reliability Coordinator in its SOL methodology is required to have a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	

Daniela Atanasovski - APS - Arizona Public Service Co. – 1	
Answer	
Document Name	
Comment	

AZPS does not consider the intent of R4.2 to be clear. The language “more servere” is broad and open to interpretation. AZPZ requests that the STD add additional clarifying language to R4.2. R4.2 Required that stability limits are established to meet the criteria specified in Part 4.1 for the contingencies identified in requirement R5 applicable to the establishment of stability limits that are expected to produce more severe system impacts on its portion of the BES. Additionally, AZPS supports the comments submitted by EEI regarding the need to extend the implementation dates for Requirements FAC-011-4 and TOP-001-6. AZPS agrees that entities will see an addition in workload to document and track what is expected to be a significantly larger number of documented exceedances under the proposed new FAC-011-04 and associated TOP-001-001-6. Companies will need to make certain enhancements to systems such as their energy management systems (EMS) and/or Real-time Contingency Analysis (RTCA) tools to accurately track and validate exceedances. While many entities may already utilize these tools to track exceedances, most will have to further enhance those tools if they are using dynamic line ratings (e.g., ambient temperature ratings or wind speed adjusted ratings). It is our understanding that most of the EMS and RTCA systems are not currently set up to distinguish the validity of exceedances in these situations. To address this issue, the industry will need time to make these adjustments. Consequently, the 12 month implementation timeframe would be insufficient to implement the new requirements and therefore request that the SDT extend the implementation plan to at least 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language for R4.2 has been modified to match the language used in the NERC TPL standard. The implementation plan has also been extended to 24 months.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	

Document Name	
Comment	

The addition of R4.7 in FAC-011-4 will have an impact on interconnection with lower system inertia such as the Québec Interconnection.

Because of its unique characteristics (main generation centers located in the north, remote from the main load centers in the south), The QI has no potential viable BES Island in underfrequency conditions. Therefore, the use of the UFLS Program does not relate to system separation.

The Quebec Variance in the NERC Standard PRC-006-3 reflects that situation.

As mentioned in the rationale box for PRC-006-3 requirement D.A.3, the UFLS Program is part of the Hydro-Québec TransÉnergie defense plan to cover extreme contingencies along with two other RAS. Therefore, taking into account the reality of the QI, the use of the UFLS Program would relate more to R4.6 rather than R4.7.

We respectfully request the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comply with FAC-011-4, FAC-014-3, TOP-001-6, and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate, and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmission Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, we are requesting the SDT consider extending the implementation timeframe to at least 24 months.

We would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which type of owner-provided Facility Ratings are to be used…’.

The definition of SOL includes thermal, voltage, stability, and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

1. The utilization of RAS is allowed under R4.6. If the RAS utilizes frequency sensor devices and shed load accordingly, then it is allowed under R4.6. This is different than an actual UFLS program that is often use as a Safety-Net. The spirit of R4.7 is to not allow reliance of a Safety-Net in a normal day-to-day operation.
2. The implementation plan has been extended to 24 months
3. With regards to R2. The current language states “… to determine which owner-provided Facility Rating”. This current language is more flexible than the proposed language. No changes are made in R2.
4. The intent of R2 is to allow each RC to include in its methodology Facility Rating to be used in operations as its applicable SOLs.

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

The changes to this standard would place a considerable reporting requirement on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to work out SOL reporting methodology should be extended to at least 24 months. Additionally, the changes to this standard places the obligation ont the Reliability Coordinator to communicate SOL exceedance; however, if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could potentially become an administrative compliance exercise that distracts Real Time Operations

Likes 0	
Dislikes 0	

Response

Thank you for your comment. After considering industry comment, the implementation plan has been extended to 24 months.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute’s response to Question No. 3.

Likes 0	
Dislikes 0	

Response

Please see respond to EEI’s comment

Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	
Document Name	
Comment	
NV Energy supports the following comments provided by EEI: *As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.*	
Likes 0	
Dislikes 0	
Response	
Please see respond to EEI’s comment. The implementation plan has been extended to 24 months.	
Daniel Gacek - Exelon – 1	
Answer	
Document Name	
Comment	

On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Please see respond to EEI's comment	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

As stated in our comments for question 1 (above), changes to FAC-011-4 place a considerable reporting obligation on SOL exceedance. Therefore, the implementation period of 12 months for the Reliability Coordinators and Transmission Operators/Transmission Owners to develop new SOL reporting methodology and associated system enhancements merit extending the implementation period to at least 24 months. While this standard places the obligation on the Reliability Coordinator to communicate SOL exceedance; if the information is not used by the Reliability Coordinators for Real-time monitoring and/or Real-time Assessments, it could become potentially an administrative compliance exercise that distracts Real Time Operations personnel from focusing on reliability. These new obligations also could be inconsistent with the ongoing work of the NERC Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

The implementation plan has been extended to 24 months.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

Requirement R3.5 implies that adjacent Transmission Operators need to have common System Voltage Limits. While theoretically this might seem appropriate, it should be up to the adjacent Transmission Operators to determine acceptable System Voltage Limits for their systems. The voltage limits of adjacent Transmission Operators don't necessarily need to be common, however ITC agrees that Reliability Coordinators should be utilizing the same System Voltage Limits as the Transmission Operators. We also believe that adjacent Transmission Operators should coordinate their individual System Voltage Limits rather than requiring common System Voltage Limits. The intent of the requirement should be reflected in the language.

Another option would be to modify Requirement R3.5 to say: "Define the method for ensuring that System Voltage Limits are coordinated between Reliability Coordinators and Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection." Requirement R5 seems to imply that all single contingency events listed in Requirement R5.1.1 should be included in the set of contingency events for use in determining stability limits. However Requirement R4.2 indicates that stability limits are established for only the contingencies that are expected to produce more severe system impacts. Requirement R4.2 is more appropriate as it would be unduly burdensome to expect that stability simulations be performed for all of the contingencies listed in Requirement R5.1.1. Requirement R5 should be split to make it clear that only the contingencies that are expected to produce more severe system impacts need to be considered for determining stability limits while all single contingencies (identified in Requirement R5.1.1) should be considered when perfomring Operational Planning Analysis and Real-time Assessments. Implementation of these modifications to the standards will require collaboration between some Reliability Coordinators and their respective Transmission Operators to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. The implementation timeframe should be extended to at least 24 months in order to provide more time to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. For R3.5, the SDT believe that System Voltage Limit is applied to each BES bus/station as stated in R3.1; as such, each bus will have a single limit. Requirement R3.5 require the RC to define a method to determine the common voltage limit. It does not require to define the limit itself. The method could require coordination amongst the neighboring entities.	

2. With regards to R5, the SDT has add more clarification in the rationale in R4.2 and R5. 3. The implementation timeline has been extended to 24 months.	
Robert Hirchak - Cleco Corporation – 6	
Answer	
Document Name	
Comment	
Implementation plan of 12 months is too short to develop operator tools to track.See MISO and EEI comments.	
Likes 0	
Dislikes 0	
Response	
The implementation plan timeline has been extended to 24 months	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Lee Maurer - Oncor Electric Delivery – 1	
Answer	
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	

Response	
Please see respond to EEI comments	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ‘ which ***type of*** owner-provided Facility Ratings are to be used...’.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don’t believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a ***type*** of contingency for…'.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. The implementation timeline has been extended from 12 months to 24 months. 2. With regards to R2. The current language states "… to determine which owner-provided Facility Rating". This current language is more flexible than the proposed language. No changes are made in R2. 3. The intent of R2 is to allow each RC to include in its methodology Facility Rating to be used in operations as its applicable SOLs. 4. The SDT discussed the utilization of "set" versus "type". The SDT believes that utilizing the phrase "set of Contingency events" would be more flexible and will allow RC to define the sets of Contingency events. The term "set" here is referring to the Contingency events and not contingency.	
Bobbi Welch - Midcontinent ISO, Inc. – 2	
Answer	
Document Name	
Comment	
MISO supports the comments filed by the IRC SRC. The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its	

respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.

The IRC/SRC would also like to suggest that additional clarity could be achieved by adding the additional phrase to FAC-011-4 R2, ' which type of owner-provided Facility Ratings are to be used...'.

The definition for SOL includes thermal, voltage, stability and frequency (BAL) Operating Limits. FAC-011-4 explicitly talks about voltage and stability but is silent on thermal. We don't believe the facility rating discussion addresses SOLs for thermal limitations. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.

Requirement R5 is looking for a set of contingency for stability, RTA and OPA analysis. A set of contingencies can be a dynamic list based on system configuration (outages) that can change throughout the day or it's simply the list of all BES elements in the footprint. We believe it would add clarity if the requirement said, 'for a type of contingency for…'.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

1. The implementation timeline has been extended from 12 months to 24 months.
2. With regards to R2. The current language states "… to determine which owner-provided Facility Rating". This current language is more flexible than the proposed language. No changes are made in R2.
3. The intent of R2 is to allow each RC to include in its methodology Facility Rating to be used in operations as its applicable SOLs.
4. The SDT discussed the utilization of "set" versus "type". The SDT believes that utilizing the phrase "set of Contingency events" would be more flexible and will allow RC to define the sets of Contingency events. The term "set" here is referring to the Contingency events and not contingency.

Brandon Gleason - Electric Reliability Council of Texas, Inc. – 2

Answer	
Document Name	
Comment	
ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The implementation timeline has been extended from 12 months to 24 months.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Requirement 6 lists language stating "that adversely impact the reliability of the BES" without detailing what is considered "adverse impact." This introduces inconsistences among the industry.	
Likes 0	
Dislikes 0	
Response	
The phrase "that adversely impact the reliability of the Bulk Electric System" is being used under the NERC currently approved definition of IROL, as such the phrase was added in the FAC-011 requirements. The Reliability Coordinator in its SOL methodology is required to have a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	

Jamie Johnson - California ISO – 2	
Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Please see response to ISO/RTO Counsel (IRC) Standards Review Committee.	

Wayne Guttormson - SaskPower – 1	
Answer	
Document Name	
Comment	
Support MRO-NSRF comments for: **1. Extend the implementation timeframe** **2. Coordinate common SOLs**	
Likes 0	
Dislikes 0	
Response	

Please see response to MRO-NSRF comments	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI's comments.	
sean erickson - Western Area Power Administration – 1	
Answer	
Document Name	
Comment	
Certainly in FAC-011-4 Requirement R6, but also in the proposed PRC-023-5, CIP-014-3, and FAC-014-3, the pairing of "expected to result in instances of instability, Cascading, or uncontrolled separation" with "that adversely impacts the reliability of the Bulk Electric System" is unnecessarily redundant given that the Glossary of Terms definition of Adverse Reliability Impact is frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. It is not clear if the SDT intends for this language to mean anything other than "expected to result in instances of instability, Cascading, or uncontrolled separation." Additionally, the SDT is perpetuating the industry-wide ambiguity of the term "widespread" by invoking the reference (without	

capitalization) to "adversely impacts the reliability." A simple, logical change is to simply retain "expected to result in instances of instability, Cascading, or uncontrolled separation" and stop there	
Likes 0	
Dislikes 0	
Response	
The SDT has attempted to modify R6 and use the phrase "that adversely impact the reliability of the Bulk Electric System" to correlate with the NERC currently approved definition of IROL. The Reliability Coordinator in its SOL methodology is required to have a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), this is done in attempt to provide some flexibility but yet clarity on those instability, Cascading, or uncontrolled separation that need to be avoided.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	
Comment	
PG&E has no additional comments	
Likes 0	
Dislikes 0	
Response	
Marco Rios - Pacific Gas and Electric Company – 1	

Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

Marco Rios - Pacific Gas and Electric Company – 1	
Answer	No
Document Name	
Comment	
In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The intent of R6 is to provide a mechanism for performance criteria (ratings, voltage/stability limits) to be coordinated between operations and planning in an effort to ensure there is appropriate agreement on these criteria. If there is confusion on the RC's methodology, there is nothing that precludes the PC or TP from seeking this clarity directly from the RC. The PC & TP are also afforded the flexibility to document a technical rationale to describe deviations between criteria used in planning from those prescribed in the RC's SOL methodology. R7 requires information communicated on corrective actions developed to address instability. As such, small generators pulling out of synchronism for P1 events is not applicable to R7.

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	
FAC-015 seems as an attempt to provide for the PC to TP heirarchy that should exist. However, it appears that there is a lack of coordination between FAC-011, FAC-014, and FAC-015. The goal should be to keep establishment of the Operating and Planning Horizon planning assessment with the closest entity (i.e. the Transmission Planner) and have the results go up the chain (subject to review and approval) from the TP to the PC to the RC and down to the TOP. The existing combination appears to include would that will not be used and is therefore wasting time and not accomplishing reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FAC-015 is not part of this posting. The SDT embedded the requirements into the current draft of FAC-014 posted in conjunction with this project.	
sean erickson - Western Area Power Administration - 1	
Answer	No

Document Name	
Comment	
WAPA agrees with removing the redundancy of the proposed FAC-015-1 and part of the shift of those requirements to the revised FAC-014-3. However, the proposed FAC-014-3 Requirement R6 remains redundant to existing obligations of MOD-032-1 and TPL-001-4 (soon -5) Requirement R1. The proposed Requirement R6 establishes a significant Compliance risk to planning entities who seek to plan the future transmission System for expansion and load growth, and ignores that Facility Ratings of the moment may not exist in the future planned System. In the proposed Requirement R7, it is unclear what reliability objective is accomplished that is not redundant to the existing IRO-017-1 Requirements R3 and R4. Furthermore, if there is a need to modify TPL-001-4 (soon -5) Requirement R8 to address annual Planning Assessment distribution, it should be revised there. Finally, to reiterate the comment above, FAC-014-3 Requirement R8 is not clear about requiring Planning Coordinators to communicate that “big-3” impacts during a particular planning event (e.g. see Cascading during simulation of a P6 event) were ***observed*** versus that “big-3” impacts ***caused*** a failure to meet System performance requirements. Here, the SDT is making a different interpretation than most planning entities make regarding TPL-001-4 (soon -5). It is not simply that “big-3” impacts were observed; it is that the “big-3” impact required a Corrective Action Plan (CAP) because the Contingency caused a failure to meet System performance requirements of Table 1. In other words, for a P6 event that yields Cascading, the Table 1 performance requirements may allow shedding Non-Consequential Load as part of the allowable mitigations such that System performance requirements are met (and no CAP). WAPA requests that the SDT reconsider the incorporation of the planning entity requirements into FAC-014-3 and, if retained, clearly state the intended reliability objective to retaining them there.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6	

of TPL-001-4, compared to that reflected in the RC's SOL Methodology. IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. R8 is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Wayne Guttormson - SaskPower – 1	
Answer	No
Document Name	
Comment	
Understand the good-faith intent of the SDT, but fundamentally the proposed requirements are TPL 001 based (and perhaps even FAC 008 based) and should be placed in the applicable standard if deemed acceptable. The draft standard appears to mandate the Facility Ratings, System steady-state voltage limits and stability criteria to be used by the PC/TP, as set by the RC/TOP methodology. It would probably be	

more effective to rewrite the drafted FAC-014 standard for the RC's/TOP's to provide their associated technical rationales (beyond a methodology) for the defined operating limits to the PC/TP for input into the TPL assessments.

In general, having standards placing requirements for other standards (as a standards setting practice) risks creating confusion. Also support the MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Jamie Johnson - California ISO – 2

Answer	No
Document Name	

Comment

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

CAISO believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. Keeping “like” requirements together in one standard will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid undue regulatory burden and support the efforts of the Standards Efficiency Review project. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn without adding Requirements R6 to R8 in FAC-014-3. Accordingly, we recommend:

- Requirements R6 to R8 be removed from FAC-014-3
- The phrase “ and that Planning Assessment performance criteria is coordinated with these methodologies.” be removed from the Purpose (Section 3) of FAC-014-3
- The Planning Coordinator and the Transmission Planner be removed from the Applicablity Section.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Applicable Facility Ratings Duration Criteria was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2), whose purpose is “To establish consistent modeling data requirements and reporting procedures [for each Transmission Owner, Transmission Service Provider, Generation owner, Resources Planner, and Balancing Authority]. TPL-001-4, R1 requires each Planning Coordinator and Transmission Planner to maintain models that use data consistent with that provided in accordance with the MOD-032 Standard that represent projected System conditions. TPL-001-5 further requires that Applicable Facility Ratings shall not be exceeded and that system adjustments are allowed to mitigate rating exceedances if such adjustments are executable within the time duration applicable to the Facility Ratings. If the SDT believes additional detail, such as a criteria regarding which of the Facility Ratings (30 min, 4 hour, continuous, etc.) are applicable under normal and emergency conditions is required, we suggest TPL-001-4 be updated to include those details/criteria so that all related requirements are located together. TPL 001-5 also requires the Planning Coordinator and Transmission Planner to establish system steady state voltages, post-Contingency voltage deviation and transient voltage response. Instead of making the RC's SOL methodology, which is typically developed entirely from the operations perspective without involvement of the PC(s) and TPs, binding on PCs and TPs, TPL-001-5 can be modified so that the RC is a party in the development of the criteria, possibly through a process that is led by Regional Reliability Organizations such as WECC.

As we noted above, keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

In addition, reading the proposed Requirement 6.2 of FAC-011-4, it doesn't appear that there is a material risk for the PC and TP to use less restrictive criteria than the RC that makes including Requirement R6 in FAC-014-3 necessary.[1]

[1] The system performance standards FAC-011-4 requires the RC to include in its SOL methodology are:

Ø System performance for no contingencies demonstrates flows and voltages are within normal ratings but emergency limits may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

Ø System performance for single contingencies demonstrates flow through facilities and voltages are within applicable Emergency Ratings and System Voltgae Limits. Steady steate post-Contingency flow through a facility must not be above the Facilitiy's highest Emergency Rating.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to either: (1) actually include the desired criteria, including the Applicable Facility Ratings Duration Criteria, in FAC-014-3 possibly using similar language as used in Requirement R6 of FAC-011-4 while maintaining consistency with the requirements in TPL-001-5 mentioned above, rather than leaving it to the RC's SOL methodology, or (2) to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings criteria, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

If on the other hand it can be assumed that the SDT is referring to Applicable Facility Ratings Duration Criteria rather than individual Facility Ratings, System voltage limits rather than Facility specific voltage limits and system stability limits then the provision of technical rationale be limited to the Regional Reliability Organization (RRO) as part of the established compliance monitoring process rather than to multiple entities to avoid putting additional regulatory burden on PCs and TPs.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 or Requirement R8 of TPL-001-5 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion, avoid undue regulatory burden, and support the efforts of the Standards Efficiency Review project.

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R3 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need to request this information. If the SDT believes additional detail is

required, we suggest that IRO-017-1, R3 or TPL-001-5, R8 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid placing undue regulatory burden on entities and support the efforts of the Standards Efficiency Review project. We strongly oppose the requirement to inform multiple entities including generator owners because, that could take planning engineers away from their core job. The existing FAC-014 limits such communication to the affected RC. We recommend that arrangement remain unchanged.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner’s responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC’s SOL Methodology. IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the	

information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

With respect to Requirement R6, ERCOT believes the language contained in the prior draft of FAC-015 should be utilized. The current draft of FAC-014 seems to suggest that responsible entities must provide a technical rationale to each Transmission Planner, Transmission Operator, and Reliability Coordinator in the event of the utilization of a higher rating than was provided for an upgraded circuit. Accordingly, ERCOT suggests replacing the proposed language of Requirement R6 with the language previously utilized in Requirements R1, R2, and R3 of FAC-015.

With respect to Requirement R8, ERCOT believes the Planning Coordinator (PC) and Transmission Planner should communicate only the limited information each Transmission Owner and Generator Owner (GO) needs to know, not necessarily the full details regarding the nature of the instability, Cascading, or uncontrolled separation. ERCOT suggest the use of the following language in Requirement R8:

Each Planning Coordinator and each Transmission Planner shall provide an annual communication to Transmission Owners and Generation Owners that own Facilities that meet the following conditions:

1. The Facility is part of a planning event contingency that the Planning Coordinator or Transmission Planner has identified in its annual Planning Assessment would cause instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the BES if a limit is exceeded; or

2. The Facility is part of a contingency associated with an established IROL or stability limit, which was provided to the Planning Coordinator or Transmission Planner under Requirement R5, Part 5.2.4.

ERCOT also suggests modifying the standards that utilize such information, which are part of this ballot/comment period, to include "Facilities identified in FAC-014" or "FAC-014-3, Requirement R8" as appropriate so that the facilities that must meet those requirements include part 2 suggested above.

ERCOT further notes that it intends to vote in favor of FAC-014-3, provided the foregoing suggested modifications are incorporated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Requirement R6 in the current draft of FAC-014 is a simplification of the R1 – R3 language in the previous posting of FAC-015. The SDT believes the intent of the previous FAC-015 requirements is preserved in R6 of FAC-014.

The SDT took your comment regarding FAC-014-3, R8 under consideration and modified the language accordingly. This change will be reflected in our next posting of FAC-014-3.

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No

Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all.

R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about

Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the ***(delete - criteria for)*** Facility Ratings, System ***steady-state*** Voltage Limits and stability ***criteria*** as ***determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC’s SOL methodology (FAC-011-4, R9).***

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

· The Planning Coordinator may use less limiting Facility Ratings ***as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon***, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the

2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014, as well as FAC-011-4. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology. IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	

Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

FAC-014-3 R6

The SPP Standards Review Group asks the SDTs consideration that coverage of FAC-014-3 is included in the data provided in MOD-032-1, and in the model building in TPL-001-4 R1, where the models contain Facility Ratings, System steady-state voltage limits, and stability criteria that are equally limiting or more limiting than the ones utilized by the Reliability Coordinator (RC).

The SPP Standards Review Group asks the SDTs consideration of these differences in the scope for TPL-001-4 R1.

The development of Facility Ratings is the responsibility of the Transmission Owner (TO) in accordance with FAC-008-3. To allow the Planning Coordinator (PC) or Transmission Planner (TP) to develop a “less limiting”, “higher” Facility Rating, could lead to unrealistic and/or invalid Planning Assessments.

The PC and/or the TP should not have the ability to overrule the TOs capability to maintain conservative Facility Ratings in accordance with manufacturer recommendations to protect its personnel and equipment.

If the PCs and TPs want to adjust system models with a higher Facility Rating based on a proposed system upgrade, that is included in TPL-001-4 R1, Part 1.1.3. FAC-014-3 R6, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures. **FAC-014-3 R7** The SPP Standards Review Group asks the SDTs consideration that TPL-001-4 R8 is for the PC and TP to share information on their annual Planning Assessments. The SPP Standards Review Group recommends that the list of entities in TPL-001-4 R8 include RCs and TOPs the ability to request and receive the information. FAC-014-3 R7, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures. **FAC-014-3 R8** The SPP Standards Review Group considers existing coverage of FAC-014-3 R8 in TPL-001-4 R8. The SPP Standards Review Group recommends that the list of entities in FAC-014-3 R8 include TOs and Generator Owners (GOs) the ability to request and receive the information. FAC-014-3 R8, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the

2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Additionally, there is no ability for the PC or TP to overrule the owner in the development of Facility Ratings. The owner, per FAC-008, develops and communicates its Facility Ratings and any relevant assumptions for these ratings. The operators and planners are then required to use these ratings, or the appropriate subset of them in the planning and operating studies of the system. The intent of R6 in the current proposal is to ensure planners are not using less limiting ratings than the RC has allowed for in operations (example: The PC & TP should not plan to a 30-minute rating if the RC only allows for operators to operate to a 2-hour rating).

R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

The proposed requirements R7 and R8 in FAC-014-3 are unnecessary. Requirement R5 ensures that the Reliability Coordinators provide the Plannning Coordinators and Transmission Planners the SOLs for their respective areas. If instability is identified in the Planning Assessments which drives an SOL, it would be provided to the TOPs through instabilitie identified by requirement R5. If the identified instability does not require an SOL then providing that information to TOPs could lead to uncertantity as to what to do with the information. Many of the instabilities identified by Planning should be items strictly for the Planning Horizon, as Planning should be addressing them with Corrective Action Plans prior to them making it to become a Real Time Operating Horizon SOL issue.

FAC-014 Requirement R6 is more appropriately placed in the TPL-001 standard to avoid possible confusion in completing the task in finalizing the completion of the models needed for performing the Near Term Assessments. All of the other requirements for the models are identified in this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R5 of the current draft for FAC-014 is RC information being communicated to other entities. R7 & R8 involve information identified by the planners being communicated to the appropriate entities. This represents different communication paths involving different sets of data/information. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI is supportive of the general concepts for Requirements R6 through R8, the language lacks sufficient clarity to address what results or outcomes are expected. Given this ambiguity, the outcomes could result in inconsistent application across the various regions. Moreover, the current language in these three requirements do not adequately conform to the tenant of a Results Based Standard. For these reasons, we cannot support the currently proposed draft of FAC-014-3 at this time.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The ambiguity referenced and the risks it presents is not particularly clear so the SDT cannot respond further or determine an action plan to address.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 “Establish and Communicate System Operating Limits” should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.

Southern Company also suggests a modification to R7 of the proposed FAC-014-3 that will help focus the communication of any instabilities identified in the Planning Assessment to include only those contingency events which are the most impactful, as follows:

R7 Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the near-Term Transmission Planning Horiozon, ***using planning event contingencies only****, to each impacted Reliability Coordinator.*

FAC – 014 R7 and R8 could result in burdensome communication even if there isn't any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

Modify the last sentence of FAC-014 R7 from "This communication shall include:" to "This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:"

Modify the first sentence of FAC-014 R8 from "shall annually communicate any instability…" to "shall annually communicate if there is any identified instability……."

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Clarifying wording changes to R7 & R8 were considered, and changes were made to R7 to have the PCs and TPs identify only the facilities to the transmission and generation asset owners. The SDT considered your suggested revisions to R7 and R8, but considered the value of an annual affirmation of "no instability impacts" more clear and precise than the suggested revision implying "no instability impacts" exist if no communication occurs.

Michael Jones - National Grid USA – 1	
Answer	No
Document Name	
Comment	
FAC-014-3 Requirements (R6 – R8) are not well aligned for inclusion in a FAC Standard and there are already similar requirements in TPL-001-4. Requirement R8 in FAC-014-3, which requires annual communication of any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment, appears to already be covered by requirement R8 in TPL-001-4. In addition, FAC-014-3 Requirements (R6 - R8) are only related to the Near-Term Transmission Planning Time Horizon. There appears to be a need for further clarification regarding the relevant Time Horizon(s) which reference: "Time Horizon: Long-term Planning."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. The Near-Term Transmission Planning Horizon was chosen since the beginning of this time horizon is where you have overlap with the operating horizon. Additionally, a focus on near-term information from planners to be communicated to operators is typically more relevant and certain and is therefore of more use to operators.	

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in Order No. 777.	
Daniel Gacek - Exelon – 1	
Answer	No
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy does not agree with the proposed requirement R6 of FAC-014-3. The proposed requirement requires additional clarity on the potential opportunity of a RC creating a Facility Rating based upon its own SOL methodology, and removing the ownership provided to Entities through FAC-008-3. FAC-014-3 requirement R6, currently reads that each Planning Coordinator and Transmission Planner shall implement a process to use Facility Ratings…that are equally limiting or more limiting than the criteria for Facility Ratings…as described in its RC's SOL methodology. NV Energy currently interprets this this as the RC can create a Facility Rating based on its own SOL methodology. Under this interpretation of the requirement, NV Energy cannot approve the current draft of the requirement R6.. Additionally, the remainder of the Standard, FAC-014-3, states that the PC and TP may use less limiting Facility Ratings, if the Entity provides a technical rationale. NV Energy interprets the intention of this language that the TP can use a less limiting element (higher facility rating) than what the RC provides, but that isn't entirely clear in the requirement's current draft.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The RC is bound to use the owner-provided Facility Ratings. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings. The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 4.

Evergy would further respond:

Proposed Revisions Add Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to use "less limiting" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The proposed Requirements R6-R8 in FAC-014-3 all require actions associated with the PC and TP annual Planning Assessment, which is required by TPL-001. If not already sufficiently addressed by the Requirements in TPL-001, we believe it would be better to address any additional actions associated with the annual Planning Assessment in a revision to TPL-001 to avoid requirement fragmentation between TPL-001 and FAC-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The proposed FAC-014-3 Requirements R6 through R8 obligate the Planning Coordinator and Transmission Planner to share information on their annual Transmission Planning Assessments. The proposed requirements are redundant because Planning Coordinators and Transmission Planners are already required to share planning assessments under TPL-001-4, Requirement R8. Requirement R8 states: "**Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.**" The proposed requirements would be	

inefficient, increase administrative compliance responsibilities, and would be contrary to ongoing work of the NERC Standards Efficiency Review project. Alternatively, if the SDT does not withdraw Requirements R6 through R8, the intent with regard to the Time Horizon must be clarified. SOLs applied to support the Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. Stability limits identified by the Reliability Coordinator may become invalid in the Planning Time Horizon as new generation is potentially added in future power flow models. When this occurs, it is the Transmission Planner's and Planning Coordinator's stability limits that must be communicated to the Reliability Coordinator so that the Reliability Coordinator knows what to expect. Also, the two bulleted items in the newly proposed Requirement R6 are troubling. The development of Facility Ratings is the responsibility of the Transmission Owner, per FAC-008. To allow the Planning Coordinator and Transmission Planner to develop a "less limiting" Facility Rating could result in inaccurate Operational and Transmission Planning Assessments. The Planning Coordinator or Transmission Planner should not be allowed to independently overrule the Transmission Owner's responsibility to develop Facility Ratings.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings. The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.	

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC Order No. 777.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	No
Document Name	
Comment	

BPA agrees with the withdrawal of FAC-015-1 and consolidating the requirements into FAC-014-3. However, BPA offers the following comments on the new Requirements.

FAC-014-3 Requirement R6: Facility Ratings are modeling data, as developed and reported in Standards FAC-008 and MOD-032. System steady-state voltage limits and stability criteria used in Planning Assessments are criteria developed and documented in annual system assessments required by Standard TPL-001.

BPA suggests including the following language (bold. italic text added) to add clarity to R6:

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that, when developing its steady-state modeling data requirements, Facility Ratings used in its Planning Assessment*** of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for Facility Ratings described in its respective Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for System steady state voltage limits***

and stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. **FAC-014-3 Requirement 7**: BPA believes it should only be necessary to communicate information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. This is also consistent with the SDT's response to comments from the previous posting. BPA suggests including the following language (bold, italic text added) to add clarity to R7. R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The above comment for R6 does capture the SDT's intent. The SDT will review the rationale for this requirement to ensure this clarity is captured. The SDT is considering modifications, to the effect of the above comment, to R8 of the current draft of FAC-014.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	

Dislikes 0	
Response	
See response to MRO NERC Standards Review Forum comment.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OGE supports the concerns expressed by MRO-NSRF on the proposed FAC-014 R6, R7 and R8. OGE believes that the proposed R6, R7 and R8 are duplicative of requirements in TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

While the intent of the requirements in FAC-014 does not appear to be reflected in the actual words. These requirements are confusing and create ambiguity that could result in incomsistent results, especially with auditors.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The ambiguity referenced and the risks it presents is not particularly clear so the SDT cannot respond further or determine an action plan to address.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. – 3	
Answer	No
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. – 1	
Answer	No
Document Name	
Comment	

MEC supports MRO NSRF comments.

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions.*"

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC Order No. 777.

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends that FAC-014-3 R7 be modified to include the phrase "during the planning events" as an added measure of clarity. For example: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified "during the planning events" in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The reference to CAPs in R7 and the associated rationale provide the clarity suggested in this comment in the SDT's opinion.	

The request for a reconsideration of the implementation period is duly noted and will be re-evaluated by the SDT.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP disagrees with incorporating R6-R8 into FAC-014 as currently proposed. It is not clear exactly what the SDT believes the benefits would be of such an approach. FAC-014 and its obligations have historically been centric to the Operations Planning Time Horizon, not the Near/Long Term Planning Horizon as currently proposed in these most recent revisions. To do so would change the original intent and purpose of FAC-014 into something more reminiscent of TPL-001. We believe the SDT needs to clarify their strategies and intentions regarding the “mixing” of these time horizons, and for them to further consider the unintentional impacts of making such changes. The “planning assessments” proposed in FAC-014 seem redundant to that which is already required under TPL-001. We believe the SDT needs to be clear as to the intent of R6-R8 with regard to the Time Horizon. SOLs applied to support Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. If the intent is to ensure SOLs applied in the Operations Planning Time Horizon are incorporated in any Planning Assessments performed, the existing language does not accomplish this. An RC’s stability limits may become obsolete and thus inapplicable in the planning time horizon as new generation is added. When this happens, it is rather the TP’s and PC’s stability limits that ought to be communicated to the RC so the RC knows what to expect in the future. If industry and the SDT believe that the obligations proposed in R6-R8 are indeed worth pursuing, it may be worth considering including them within a new FAC standard of their own. The revised FAC-014 R6, R7, and R8 apply directly to the conduct and communication of planning assessments. While we recognize that TPL-001 is not within scope of the project’s SAR, we believe such obligations are already captured as part of TPL-001. FAC-014 R6 states “Each Planning Coordinator and each Transmission Planner shall implement a documented process”, but it is not clear exactly where the creation of this documented process is/was originally required.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The currently approved version of FAC-014 contains requirements of planners to establish and communicate SOLs per the PC SOL methodology. Therefore, the concept of the planning horizon is already fully embedded in FAC-014. The retirement of FAC-010, as proposed by the SDT, makes it necessary to replace the current SOL-based requirements with more appropriate mechanisms to ensure communication and coordination between planners and operators is provided for in the standard.

The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The data provided through TPL-001-4 only provides information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

“These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments”.

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models “*shall represent projected System conditions.*”

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC Order No. 777.

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

R6. This requirement is out of place in FAC-014 and should already be covered in the data provided via MOD-032-1 and model building effort via TPL-001-4 R1, which specifies that models "*shall represent projected System conditions*". Therefore, why wouldn't the models already contain Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the Reliability Coordinator? If there are significant differences between how the system is being planned and how it's being operated, then that should be within the scope for auditing TPL-001-4 R1 today. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project.

Additionally, the two bulleted items are problematic since the development of Facility Ratings is the responsibility of the Transmission Owner in accordance with FAC-008. To allow the Planning Coordinator or Transmission Planner to develop a "*less limiting*" (higher) Facility Rating could lead to unrealistic and/or invalid Planning Assessments. The Planning Coordinator and/or Transmission Planner should not be allowed on their own to overrule the Transmission Owner's ability to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment. However, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, then that is already allowed via TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. Therefore, the list of entities in TPL-001-4 R8 should be enhanced to allow Reliabilty Coordinators and Transmission Operators the ability to request and receive this information.

R8. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. It also appears in the rationale document for FAC-014 the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners. Therefore, the list of entities in TPL-001-4 R8 should be expanded to allow Transmission Owners and Generator Owners the ability to request and receive this information.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC Order No. 777 777.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there	

should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, “instability” must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent of R6 is to provide a mechanism for performance criteria (ratings, voltage/stability limits) to be coordinated between operations and planning in an effort to ensure there is appropriate agreement on these criteria. If there is confusion on the RC’s methodology, there is nothing that precludes the PC or TP from seeking this clarity directly from the RC. The PC & TP are also afforded the flexibility to document a technical rationale to describe deviations between criteria used in planning from those prescribed in the RC’s SOL methodology. R7 requires information communicated on corrective actions developed to address instability. As such, small generators pulling out of synchronism for P1 events is not applicable to R7.	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	

Likes 0	
Dislikes 0	
Response	
See response to SEE, EEI and MISO comments.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Thank you.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion we need to be careful that there is only one methodology for SOL's going forward. We agree with the proposed requirements but also suggests that the team consider instead adding these requirements within TPL-001, which deals with the Planning Assessment and correspondence/communication of the Planning Study to affected entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Facility Ratings? This set of standards talks about	

Steady State Voltage Limits, Stability Limits, but us silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Per the definition, the maximum current, real or reactive power flow should constitute the thermal limits for facilities, which is part of the Facility Rating. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
FAC-014-3 The statement "any instability identified in its Planning Assessment of the Near-Term Transmission…" seems unclear. I think an improvement and more clear statement might be, "any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…".	

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Clarifying modifications to R7 and the associated rationale are being considered by the SDT.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
1. The IESO is concerned that there is no requirement for the affected RC to provide feedback on the technical rationale provided by the PC or TP for using less limiting ratings. The IESO proposes to add a sub-requirement to establish this feedback loop between the affected entities and the PC or TP. The proposed requirement would mirror Requirement R8, sub-requirement 8.1. of Reliability Standard TPL-001-4 which allows the recipient of the Planning Assessment results to provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments: ***Proposed Requirement R6, Sub-requirement 6.1:*** ***"The recipient of the technical rationale may provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments"***	

Alternatively, the IESO would like to clarify if Requirement R8., subrequirement 8.1 is the feedback loop that can be used to address the lack of input from the affected entities on the technical rationale provided by the PC or TP on the use of less limiting ratings (this is based on the assumption that the technical rationale would be part of the Planning Assessment results).

2. Similar with the Reliability Standard TPL-001-4 where an RC can provide input on the Planning Assessment criteria, the IESO believes that the PC and TP should be afforded the reciprocal opportunity to provide input to its RC's methodology and have the RC provide a document response.

The IESO proposes to add *Sub-requirement R9.3 to FAC-011-4 as follows:*

"9.3. If a recipient of the Reliability Coordinator SOL methodology provides documented comments on the methodology, the respective Reliability Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments."

3. We find that Requirements R7 and R8 are duplicative of existing communication requirements within other Reliability Standards. Specifically,

{C}o **Requirement R7 requires the PC and TP to communicate, annually any CAP identified in its Planning Assessments to the RC. Requirement 8 in TPL-001-4 requires the PC and TP to provide its Planning Asssessment results to affected entities, which include any CAP developed in R2 Sub-requirements 2.7 of TPL-001-4; and**

{C}o **Similarly, Requirement R8 requires the PC and TP to communicate, annually , any instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES in its Planning Assessment of the Near-Term Transmission Planning Horizon to TOs and GOs. All Planning Assessments performed by PCs and TPs are governed by other standards (TPL-001, PRC-012, PRC-023 etc.) and the processes required by those standards already include provisions for the communication of those results to the entities that have a reliability need.**

We suggest that Requirements R7 and R8 be removed to avoid duplication with existing communication obligations for the PC and TP.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

The feedback loop for the RC to the PC and TP concern is noted. This was not included in the current draft language due to a potential perception of "approval" of the rationale by the RC, which could imply an authority by the RC over the planners. This authority is not supported in the NERC functional model and a requirement for the planners to document a response only seemed administrative in nature and was thus not included.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the specific information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC Order No. 777.

Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	
Answer	
Document Name	FAC-014 SBS Comments 8-3-2020.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	

R3. What is the purpose of the Transmission Operator providing its SOLs to the Reliability Coordinator? If it's for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then keeping this requirement is redundant with the data specification in IRO-010-2 and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Furthermore, by definition SOLs change continuously based on "*a specified system configuration*". Therefore, does the SDT expect the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment? This is another reason why the information/data exchange activity needs to remain within IRO-010-2, where each Reliability Coordinator can determine the items that need reported, the method and a timeframe based on their individual operating environment.

R5.1 and R5.2. If one purpose of Project 2015-09 is to eliminate planning-based SOLs and IROLs, then what is the purpose of the Reliability Coordinator providing them to the Planning Coordinator and Transmission Planners in this requirement? If it's for the purpose of better aligning planning and operations, then where is the requirement for the Planning Coordinator or Transmission Planner to use them in the models for the Planning Assessments? If there isn't a corresponding obligation, then it potentially becomes an administrative compliance exercise that isn't benefiting reliability. Additionally, the model building topic is covered in MOD-032-1 and if the intent is to use additional information identified during operations in the models for TPL-001-4 Planning Assessments, then MOD-032-1 should be enhanced and the

Reliability Coordinator should be added to the applicability. Having it dispersed in other standards could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient. **R5.3 and R5.4.** What is the purpose of the Reliability Coordinator providing IROL information to the Transmission Operators? If it's for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep these requirements detached in FAC-014 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	

Response
R3: This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010 and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. This requirement does not preclude the RC from having the flexibility of specifying the SOL information it requires from the TOP to satisfy the requirement within its SOL Methodology such that there's a clear expectation of what's to be provided. R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may influence them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information which is key to maintaining reliable operation across our interconnections.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. R3: This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010 and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. This requirement does not preclude the RC from having the flexibility of specifying the SOL information it requires from the TOP to satisfy the requirement within its SOL Methodology such that there's a clear expectation of what's to be provided. R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement. R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information which is key to maintaining reliable operation across our interconnections.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

It is also important that RC and/or TO provide technical rationale to PC if they are using less restrictive SOLs than PC's SOLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed standard requirement R6 suggests the PC and TP use more restrictive limitations, ratings, and performance criterion. Since this is in line with the proposed requirement, the SDT doesn't see why a rationale would be needed. If opposite were the case, i.e. where RC and TO are proposing to more restrictive criterion than PCs and TPs are using, the PC and TP need to flag this and work with the RC and TOP to build the technical rationale as the requirement is on the PC and TP to ensure.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments". **R3 Issues** A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT: 1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments? If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project. 2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?	

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP – 5	
Answer	
Document Name	
Comment	
If retained, we believe FAC-014 should be revised as “Each Reliability Coordinator shall establish stability limits to be used in operations when *an instability* impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Your suggestion was used to revise the language in the requirement.	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	
Document Name	
Comment	
R5.5: This language is awkward. Please clarify and reword to capture intent.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. This is a statement that highlights that the RC is required to provide any of its TOPs, upon their request to the RC, with SOL information pertaining to another TOP area that is within its RC's footprint. This is explained in the rationale for R5.5. Further information will be added to the rationale document as to why this may be useful. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need detailed information regarding another TOP's SOLs.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them.

Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement. R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	

Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Thank you for your comment. R5.1 and R5.2: Please see the explanation offered in the rationale for Requirements R5.1 and R5.2. The SDT believes that using the "upon written request" language may result in important SOL information not getting to the TP and RC such that they may not be aware of what to look for in their Planning Assessments to identify potential impacts to known stability issues or new issues that may arise. Requirements in the MOD and TPL standards do not cover the information with enough specificity for the RC to understand the necessary IROL and stability related information required to be provided under R5.2. See Q3 response to your suggestion regarding a new time horizon.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	
Document Name	
Comment	

Measure M3, the phrase "in accordance with its Reliability Coordinator's SOL methodology" should be stricken since it is stricken in the requirement. Proposed language "in accordance with requirement R3" would suffice.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This has been corrected.	
Mark Holman - PJM Interconnection, L.L.C. – 2	
Answer	
Document Name	
Comment	
R3 - The new language provides no suggested timeline beyond the Time Horizon of Operations Planning. Many SOLs, the limit itself, not the basis for the limit which can include Facility Ratings, at minimum, are derived/determined in the Real-time horizon. The Rationale gives several options/examples of how this might transpire which are not governed by the requirement language, which drops the suggested option of "*in accordance with its Reliability Coordinators SOL methodology*". As such, the proposed SDT language for R3 is ambiguous and either allows the TOP to indicate an SOL as they see fit, or continuously. Yet, the measurement indicates that evidence demonstrating the TOP provided its SOLs in accordance with its RC's SOL methodology. Which seems appropriate. R5 - RC's have Facility Ratings. RC's have stability limits. RC's have criteria for the determination of IROLs. The value of the SOL, which could include, for example a single temperature set rating for a given facility, is of minimal benefit to a PC or TP and is an incomplete set.	

· The methodology and ratings sets that can lead to potential SOLs would be of value to the PC or TP. As written, this requirement and many of its subparts serve minimal reliability value and is highly administrative in nature; and is not an improvement over the current FAC-014-2 R5. Requiring the formalized exchange of such information is not necessarily a determination that it is of value to the recipient. Suggest R5 be rewritten to align with R6 and provided the criteria, methodology and supporting data (including Facility Ratings) that may be both relevant and beneficial to a TP or PC. Alternatively, providing a list of SOL exceedances and/or trends may also be of some value to the PC or TP. A long list of SOLs with no additional context is an overlap of other requirements/obligations set on the TO/GOs in other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The time horizons for R3 are Operations Planning, Same-day Operations, Real-Time Operations as specified on the proposed clean version of the FAC-014-3 standard as linked to the 2015-09 Project page on the NERC website. In the requirement for R3, "in accordance with its RC methodology was removed", as provision of SOL information may be agreed upon through means other than within the methodology itself. See the rationale for R3 for more explanation. R5: This requirement is intended to be all encompassing in the areas of concern and give the RC the flexibility to work with PC and TPs to decide what is and isn't important information that should be shared within the terms mandated within the requirement.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	

Texas RE recommends the SDT consider the following:

- In Requirement R4, add “adjacent Reliability Coordinators Areas **within its Interconnection** or” unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections.
- Revise Part 5.4 from “each established stability limit or each IROL” to “each established stability limit **and** each IROL applicable to the impacted Transmission Operator”. Both the stability limit and the IROL should be provided to each impacted Transmission Operator.
- In Requirement R6, the term “System steady-state voltage limits” is not defined. Is this term intended to be different than the proposed term “System Voltage Limit,” which was introduced in this project?
- Include a check and balance for use of the less limiting parameter in Requirement R6. This requirement allows for any criteria to be used (i.e. less limiting Facility Rating, etc) as it simply states a “technical rationale” has to be provided to any entity affected by a “less limiting” parameter.
- Requirement R6 uses “affected Transmission Planner, Transmission Operator and Reliability Coordinator,” while R7 references “impacted Transmission Operator and Reliability Coordinator” and R8 references “impacted Transmission Owner and Generation Owner.” Unless there is a specific reason for difference in verbiage, Texas RE recommends being consistent to avoid confusion and potential interpretation attempts at differences in language in the Requirements.
- Requirement R7 appears to exclude any CAP for Cascading or uncontrolled separation. Please provide the rationale for the exclusion.
- Provide more clarity in Requirement R8. In the phrase “any Facilities critical to the instability, Cascading or uncontrolled separation identified,” it is not clear what would constitute “Facilities critical to the instability, Cascading or uncontrolled separation identified,” and how these are different than “Facilities that comprise the Contingency(ies) (planning events only).”
- Requirement R8 requires the PC and TP to communicate “Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified.” Many of the updated Standards (e.g. CIP-014-3, FAC-003-5) use the applicability language “Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events”. It would be helpful if the information provided by the PC and TP directly maps to the applicability section of these other Standards. Texas RE recommends requiring that communication to the TO and GO include “Facilities that if lost or degraded are expected to result in instances of

instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events" instead of "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified."

- Requirement R8 uses the phrase "planning events only." Texas RE recommends including an explanation that these events refer to the events in Table 1 of TPL-001.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Requirement R4 as worded only speaks to stability limits that influence adjacent RC areas or more than one TOP in its area. If an adjacent RC is in another interconnection and won't be impacted, it may not need to be considered in the analysis; however, this requirement leaves room for where there may be such an impact via transfer levels on asynchronous tie-lines or unavailability of these tie-lines due to outages or a contingency. The rationale for R4 has been updated accordingly

R5.4 The SDT agrees with your suggestion.

The use of "System steady-state voltage limits" language was used to be consistent with TPL-001-4 R5 and makes use of the defined term "System" to clarify which steady-state voltage limits needed to be provided to the TP and PC and which are those are associated with System operation as opposed to operation of specific equipment. Use of the term is also is associated with the criteria that each PC and TP must follow in carrying out their Planning Assessment.

The reason the language surrounding the provision of the technical rationale was chosen was in hopes that the entities receiving it would engage the provider if they had concern around the merit of the rationale and work out an agreement. Stronger language around the confirmation of these rationales by either the RC or PC was avoided as both entities are on equal footing and one side should not have veto rights on such a rationale.

For R6 - R8, there was no intent to differentiate between impacted and affected system as worded in these requirements.

In requirement R7, there was no intention to avoid the use of cascading and uncontrolled separation with regards to corrective action plans. As cascading and uncontrolled separation is a result of instability, it falls under the same umbrella and is thus addressed by CAPs preventing instability.

Facilities that are critical to the derivation of IROLs can be different than what facilities comprise the contingencies. For example, a large generator or shunt capacitor which is not lost as part of a contingency triggering instability may play a big role in keeping healthy voltages on the system necessary to prevent instability occurring post-contingency.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	
The time horizon in R6-R8 are currently identified as “Long-Term Planning Horizon” While this aligns with the horizon of the TPL-001-4 standard where issues would be identified, it is specifically the Near-Term Planning horizon that these issues point to. We recommend	

adjusting the time horizon assocoaited with R6-R8 to more accurately reflect the portion of the TPL-001-4 assessment they are intended to align to.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT agrees with you that near-term Planning is the timeframe at which these issues will be considered. However, there's no time horizon definition for near-term planning within the body of NERC standards. Therefore, the most appropriate time horizon was chosen, the Long-term Planning Horizon.
Daniela Atanasovski - APS - Arizona Public Service Co. – 1

Answer	
Document Name	

Comment
None

Likes 0	
Dislikes 0	

Response
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	
Document Name	

Comment

NERC Standard IRO-17 obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. NERC TPL-001 includes the obligation that when the analysis indicates the inability of the system to meet the performance requirements. We believe FAC-014-3 R7 basically includes/requires the same if not similar information. If this additional detail is required, we suggest that IRO-017 be updated so that this type of request is located in a single requirement or standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. IRO-017 is specific to outage coordination whereas TPL-001 is specific to sharing with other planning entities but recognizes other entities, which may have a reliability, need. FAC-014-3 is about better coordination between Planning and Operating entities around specific aspects of the Planning Assessments and R7 in particular is about sharing details resulting from corrective action plans (CAPs) that would be of value to operations. Although there is probably some overlap in what will be shared, all three standards are focusing on a different aspect that's important for their intended purpose. The team recommends this concern is better looked at as part of a holistic review of standards efficiency.	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	
Document Name	
Comment	
NV Energy would like to communicate its additional concern over FAC-014-3, with the retirement of FAC-010-3. With the retirement of FAC-10-3, Transmission Planners will not be able to use their IROL methodology for the Planning Horizon anymore, and as stated, will be forced to adjust to their respective RC's SOL Methodology and definition of an IROL. NV Energy's concern with using a respective RC's IROL definition is the potential for the RC to identify an IROL for a more conservative loss than what a Transmission Planner would determine. NV Energy understands the need for a secure BES with the establishment of an IROL in an Interconnection; however, the ramifications of an IROL	

declaration stretch into multiple Standards that require a substantial amount of work for compliance implementation (i.e. CIP Standard suite), as well as the equipment modifications for facilities to monitor the flows on Elements within an IROL. NV Energy still believes their should still be a responsibility of defining IROLs with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The new FAC-014-3 standard allows the Planning entity to choose how to perform its assessments as long as the performance criterion used is as conservative as or more conservative than what's in the RC's SOL Methodology under the confines of TPL-001-4 requirements. The requirements for scope of coverage (consideration of elements out of service) that must be studied for planning assessments is specified in TPL-001-4.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	

Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. They will be considered by NERC staff.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	

Document Name	
Comment	
The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale.	
Bobbi Welch - Midcontinent ISO, Inc. – 2	
Answer	
Document Name	
Comment	
MISO supports the comments filed by the IRC SRC. The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are	

developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 “as is.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. – 2	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO – 2	
Answer	
Document Name	
Comment	

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

The SDT proposal to retire FAC-010 and the requirement to establish SOLs and IROLs for the planning horizon appear to be the result of the following two misconceptions:

- The "new" TPL 001-4 standard eliminates the need for developing SOLs and IROLs for the planning horizon, which is incorrect and
- SOLs are not useful for the reliable planning of the BES, which is also incorrect.

TPL 001-4 standard does not replace the need for developing SOLs and IROLs for the planning horizon and eliminate the need for the existing FAC-010 and Requirement R3 and R4 of the existing FAC-014. This is because TPL-001-4 is all about ensuring reliable service to firm load and firm transmission services. It does not require planning entities to stress tranfers on any part of the system to determine its limit. Also, since TPL-001-4 studies do not require stressing the system they are less suited to identifiying contingencies the lead to system instability,

cascading and uncontrolled separation compared to SOL and IROL Studies performed under FAC-014 R3 and R4. Even if, TPL 001-4 studies identify contingencies that lead to such adverse impacts, they would be mitigated, which means there would be no planning contingencies with such adverse impacts. SOLs are useful in the reliable planning of the system. For example, in the Western Interconnection (accepted) path ratings, which California ISO deems to be SOLs and are typically developed in the planning horizon, are used in the reliable planning of the system. In all its studies including the annual reliability assessment and local capacity studies, the CAISO ensures these SOLs are not exceeded. For example, reliability assessments and local capacity studies performed use this SOL information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale. R7 is meant to capture and highlight in the Planning Assessment any instance where mitigation measures are used such that they do not hide limitations discovered. How far to stress the system and under what assumptions limitations are found in the planning horizon is something that is unique to each entity and was not part of FAC-010 and currently not part of TPL-001-4. Therefore, the team believes although there could be stronger requirements language to better address the concern, no gap was created in retiring FAC-010.	
Wayne Guttormson - SaskPower – 1	
Answer	
Document Name	
Comment	

Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 & R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 & R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Kenya Streeter - Edison International - Southern California Edison Company – 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
No. Thank you	
Likes 0	
Dislikes 0	
Response	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	

Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	
Document Name	
Comment	
These standards appear to be fine. One general comment on various FAC standards is the use of the term "impacted." It is used as a non-capitalized term however, how is an entity supposed to determine if another entity is impacted or not? If Clark is suposed to do something or say something to an impacted RC, what criteria is it to use to determine whether RC West is just an RC or an impacted RC?	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Since no specific standard is referenced in the comment, the SDT made an educated guess that the comment was likely intended for FAC-014. After careful consideration, the SDT has determined that no additional guidance is needed in FAC-014 to clarify how an impacted entity is to be determined.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
No. Thank you.	
Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see responses provided to Edison Electric Institute.	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response provided to MRO NSRF’s comment.	
Jamie Johnson - California ISO - 2	

Answer	
Document Name	
Comment	
California ISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Please see the response provided to ISO/RTO Counsel (IRC) Standards Review Committee.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT suggests the implementation period be extended from 12 to 24 months in order to allow sufficient time to make necessary system changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has revised the Implementation Plan to extend the implementation time to 24 months.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO supports the comments filed by the IRC SRC. The IRC SRC respectfully requests the SDT extend the timeframe for implementation from 12 to at least 24 calendar months to support the changes needed to comly with FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3. Some entities will need to enhance existing tools to accurately track, validate and reconcile SOL exceedances; particularly in those instances where the Reliability Coordinator (RC) is not also the Transmisison Operator (TOP). In addition to tools, implementation of the new standards will require collaboration between the RC and its respective TOPs to revise the SOL methodology and associated processes and procedures and provide relevant training to system operators. Additionally, a 24-month implementation timeframe would provide the time needed to budget, design, develop, test, implement and train on new processes and tools prior to placing them into production, particularly in light of the ongoing operational challenges associated with the COVID-19 pandemic and the anticipated demand this will place on EMS vendors as entities compete for limited resources. For these reasons, the IRC SRC is requesting the SDT consider extending the implementation timeframe to at least 24 months.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT has revised the Implementation Plan to extend the implementation time to 24 months.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy agrees with the requirement language provided for TOP-001-6 R14, but has concerns with the language provided for the measures for R14. NV Energy has concerns with the phrase “successfully mitigated”, and it not being appropriate, even if it is just for suggested evidence. Requirement R14 states only to show a Plan that was initiated to mitigate SOLs, not to prove mitigation. While success is obviously the desired outcome, it is not the only possible outcome, and this language addition to the measures for R14 seems to extend beyond the intent of the requirement.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. After careful consideration of your comment, the SDT has determined that the measure for R14 is appropriately worded and does not go beyond the intent of R14.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	

Comment

Texas RE has the following comments for proposed IRO-008-3:

- In Requirement R1, revise Interconnection Operating Reliability Limits to Interconnection Reliability Operating Limits.
- In Requirement R5, "exceedance" is added after SOL but is not in Requirement R6. It was added in the VSL/VRF matrix for Requirement 5 and parts of Requirement R6. Requirement R6 VSL/VRF only has "exceedance" added within the first statement and not the second statements (after the "OR" in Lower, Moderate, and High VSL columns on page 12 of 15). Since the language appears to be so similar, Texas RE recommends consistency in where exceedance is added.
- Requirement R7, as well as the measure, capitalizes "Real-time Monitoring." Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized.
- Texas RE noticed the Data Retention section does not include Requirement R7. Texas RE recommends Requirement R7's data retention match Measures M1 - M3, Measure M5, and Measure M6 at a minimum.
- Texas RE noticed the Guidelines and Technical Basis has been removed from this standard, but it is still in place for other standards, such as PRC-026. Texas RE recommends following the Technical Rationale Transition Plan and determine whether the Guidelines and Technical Basis is Technical Rationale or Implementation Guidance.
- Texas RE recommends the IRO-008-3 mapping document include the BA since it is included in the standard.
- Texas RE has the following comments for proposed TOP-001-6:
- The term "Real-Time System Operators" is used in several places in the rationale document. Since it is not a defined term in NERC Glossary, Texas RE recommends using the term System Operator, which is defined.

- In Requirement R15, it is unclear as to whether the phrase “in accordance with its Reliability Coordinator’s SOL methodology” is referring to the “exceeded” SOL or the need to “inform”. The VSL/VRF matrix language structure places the phrase after “inform”. Texas RE recommends reviewing the sentence and make clarifying changes as necessary.
- Requirement R25, as well as the measure, capitalizes “Real-time Monitoring”. Real-time Monitoring is not a defined term in the NERC Glossary and monitoring should not be capitalized. It is also capitalized in the VSL/VRF matrix and the Evidence Retention sections of the standard.
- Texas RE requests justification for revising the Evidence Retention requirement for Requirement R14. This justification for the change could be captured in the mapping document for TOP-001-6.
- The mapping document appears to contain guidance on how to comply with TOP-001-6, in the statement “communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output”. This is not a method to inform the RC of “actions taken”. ICCP reflects results of actions but does not necessarily reflect the action(s) actually taken. The mapping document is not an appropriate place for putting guidance on how to comply with the standard and the process for developing Implementation Guidance can be utilized if the SDT would like to provide guidance on complying with the standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

IRO-008-3: Please refer the revised posted draft to review the following changes:

- R1. The SDT made the suggested correction.
- R6. The SDT made the suggested insertion to be consistent with R5. The VSL was also updated accordingly.
- R7. The SDT made the suggested correction.
- Data Retention: The SDT has now included R7 in data retention.
- The SDT only made comforming changes to PRC-026 and the Guidelines and Technical Basis section will be addressed in the future.
- Mapping Document: The SDT made the suggested change to include BA.

TOP-001-6: Please refer the revised posted draft to review the following changes:

- Rationale Document: The SDT made the suggested change of omitting the “Real-Time” qualifier for System Operators.

- R15. The SDT corrected the VSL to make it consistent with the requirement.
- R25. The SDT made the suggested correction for every instance in the standard.
- Mapping Document: The SDT made the suggested change to remove the compliance guidance.

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
Need to add the word "its" to the modified portion of Requirement R6.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

Please see the response provided to MRO NSRF's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Thank you for you comment. 1)The SDT updated Requirement R5 to align the notification Requirements with the communication Requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. 2)This change is out of scope for the SDT. 3) Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Please see the response provided to MRO NSRF’s comment.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Considering that "Consistent with SOL methodology" is mentioned throughout the Standard, suggest referencing "SOL expectations outlined in FAC-011-3" somewhere within the Standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Since no specific standard is referenced in the comment, the SDT made an educated guess that the comment was likely intended for FAC-014. After careful consideration, the SDT has determined that the suggested change is not necessary.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
MEC supports MRO NSRF comments. **RO-008 R5.** What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability. **IRO-008 R6.** What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Please note that the SDT only made clarifying changes, and no substantive modifications, to IRO-008 Requirements R5 and R6 in the posted draft. Specifically, the clarifying changes consisted of the insertion of phrase "in accordance with its SOL methodology" in R5 and R6 plus the insertion of "exceedance" after SOL (to ensure resulting "SOL exceedance" is consistent with "IROL exceedance") in R5. Since the comment pertains to the intent/purpose behind the R5 and R6 verbiage in the currently effective standard, which is outside the scope of changes made in the posted version, the SDT is unable to address this comment.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments". **IRO-008 R5.** What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator	

to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability. **IRO-008 R6.** What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please note that the SDT only made clarifying changes, and no substantive modifications, to IRO-008 Requirements R5 and R6 in the posted draft. Specifically, the clarifying changes consisted of the insertion of phrase "in accordance with its SOL methodology" in R5 and R6 plus the insertion of "exceedance" after SOL (to ensure resulting "SOL exceedance" is consistent with "IROL exceedance") in R5. Since the comment pertains to the intent/purpose behind the R5 and R6 verbiage in the currently effective standard, which is outside the scope of changes made in the posted version, the SDT is unable to address this comment.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
The changes to these standards place a considerable reporting requirement on SOL exceedance. Manitoba Hydro is requesting 30 month implementation period rather than, normal	

12 months implementation period to work out SOL reporting methodology with the RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has revised the Implementation Plan to extend the implementation time to 24 months.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response provided to City Utilities of Springfield's comment.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Why R25 couldn't have just been incorporated into R14? R25 basically stating a TOP has to use its RC's methodology, which indirectly implies it has to be in each TOP operating plan for the identified SOL exceedances for R14?	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Each distinct reliability activity/task must have a dedicated requirement in a NERC Reliability Standard. The SDT adhered to this guideline in drafting the new requirement R25.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	
IRO-008 R5. What is the purpose of the Reliability Coordinator notifying the Transmission Operator of SOL/IROL exceedances? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive this information from its Reliability Coordinator based on its individual operating environment. To keep this requirement detached in IRO-008 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose	

and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability. **IRO-008 R6.** What is the purpose of the Reliability Coordinator notifying the Transmission Operator when SOL/IROL exceedances are prevented or mitigated? If it's for the Transmission Operator's Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep this requirement detached in IRO-008 is contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Real-time monitoring and Real-time assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Please note that the SDT only made clarifying changes, and no substantive modifications, to IRO-008 Requirements R5 and R6 in the posted draft. Specifically, the clarifying changes consisted of the insertion of phrase "in accordance with its SOL methodology" in R5 and R6 plus the insertion of "exceedance" after SOL (to ensure resulting "SOL exceedance" is consistent with "IROL exceedance") in R5. Since the comment pertains to the intent/purpose behind the R5 and R6 verbiage in the currently effective standard, which is outside the scope of changes made in the posted version, the SDT is unable to address this comment.

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	
The standards need to be results-based and define *a clear and measurable expected outcome* for all Registered Entities. By adding "*that adversely impact the reliability of the Bulk Electric System*" implies that some instability, Cascading or uncontrolled separation is acceptable. Who determines that threshold? The Reliability Coordinator in its SOL methodology? How do we ensure a consistent expectation and application for all Registered Entities?	
Likes 0	
Dislikes 0	
Response:	
Thank you for your comment. The Planning Coordinator or Transmission Planner would make a determination based on their study results of what "*adversely impacts the reliability of the Bulk Electric System"* based on their criteria specific to their system. This provides a study results based outcome that is clear and measurable based on their criteria, and is specific to the Planning Coordinator and Transmission Planners system. CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 all contain criteria to determine what facilities require the higher level of protection and do not apply as a blanket to all facilities. Including the caveat of "*adversely impact the reliability of the Bulk Electric System"* maintains that filtering of only those facilities that require that higher level of protection. The caveat does not preclude the Planning Coordinator or Transmission Planner from considering all instability, Cascading or uncontrolled separation to be adverse to the reliability of the Bulk Electric System, but it does allow them to exclude those elements that based on their criteria and system conditions are not adverse to the reliability of the Bulk Electric System and don't merit the higher level of protection.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 – WECC	
Answer	No

Document Name	
Comment	

Regarding the changes to CIP-014, Seattle City Light has five areas of concern. The first three relate to revised Section 4.1.1.3 and the fourth and fifth address impacts to existing R1.

First, the changes to Section 4.1.1.3 to replace the reference to IROL Facilities identified by an entity's Reliability Coordinator, Planning Coordinator, or Transmission Planner with Facilities associated with instability, Cascading, or uncontrolled separation, that also adversely impact BES reliability for planning events, is inconsistent with Criteria 2.6 of CIP-002 Attachment 1, from which Section 4.1.1.3 was taken. The applicability CIP-014 is designed to conform to the criteria of CIP-002 for Medium impact Transmission Facilities. For consistency among the CIP Standards, Seattle suggests that CIP-002 Attachment 1, Criteria 2.6, also be changed along with CIP-014.

Second, the changes to Section 4.1.1.3 are confusing and perhaps redundant. As proposed, the criteria to identify applicable Facilities has two components: (i) loss that creates instability, Cascading, or uncontrolled separation, (ii) that adversely impacts BES reliability for planning events. So far as Seattle is aware, nowhere else in the NERC Standards are the "big three" bad events (instability, Cascading, uncontrolled separation) qualified in this way; they are presumed by their existence to create adverse BES impacts. In addition, the language "adverse impact for planning events" adds another layer of confusion. What is an adverse impact for a planning event? Considerable effort has been spent by NERC and industry over the years to qualify "adverse BES impact" for CIP-002, yet this new language introduces a different new concept that expands adverse impact to new territory. Additional clarity is required. As a simpler solution, Seattle suggests that the qualifier phrase "that adversely impacts…" be dropped from the proposed change to Section 4.1.1.3.

Third, the changes to Section 4.1.1.3 add a new burden on entities that was not previously present. For IROLs, there exist established processes to inform entities of the existence of IROLs and document those Facilities critical to their derivation. The "IROL Cards" and IROL website used in the Western Interconnection are examples of these processes. As a result, it is easy for entities to apply existing Section 4.1.1.3 criteria (as well as those of CIP-002 Criteria 2.6) and crystal clear to document conclusions at audit. For the proposed changes, there is no established mechanism or consistent process for Planning Coordinators or Transmission Planners to share with entities information about Facilities related to BES instability, Cascading, or uncontrolled separation, nor is there established language about how to identify such Facilities. Presumably such information is shared in some fashion as a matter of good practice, but absent any established means to do so and consistent approach to documentation, the change creates a new burden on entities to track down such information from others and to clarify findings in unequivocal, crystal clear language to satisfy any auditor. As a solution, Seattle suggests that somewhere in the body of changes introduced by Project 2015-09, there be a new requirement for Planning Coordinators and Transmission Planners to inform subject entities, in a standardized manner, of Facilities related to to BES instability, Cascading, or uncontrolled separation.

Fourth, the changes to Section 4.1.1.3 cause redundancy for CIP-014 R1. Specifically, R1 requires a transmission planning study to identify Facilities associated with instability, Cascading, or uncontrolled separation. These are the identical criteria that cause a Facility to be applicable in 4.1.1.3. As proposed, the requirement would require a transmission study on Facilities identified to be associated with instability, Cascading, or uncontrolled separation to determine if they are associated with instability, Cascading, or uncontrolled separation. Ridiculous! As a possible solution, Seattle suggests CIP-014 R1 be rewritten to exempt from evaluation any Facility meeting Section 4.1.1.3 (because it already has been so evaluated), and revise R2 to require a third party evaluation of the entity's R1 study and the Section 4.1.1.3 evaluation of the applicable Planning Coordinator/Transmission Planner.

Fifth, the different qualifiers used in Section 4.1.1.3 and R1 create unnecessary confusion. Section 4.1.1.3 qualifies applicability based on "adversely impacting the reliability of the BES reliability for planning events" whereas R1 qualifies applicability "within an Interconnection." It is not clear how these different qualifiers impact identified instances of identified instability, Cascading, or uncontrolled separation. There's enough confusion and auditor dissent for CIP-014 about how to apply the "within an Interconnection" qualifier; no new confusion is needed. As suggested above, Seattle recommends that the Section 4.1.1.3 "adverse impact" qualifier be removed, which would also address R1 confusion as discussed here. If qualifying language is desired, Seattle recommends that the same language be used in Section 4.1.1.3 and R1.

Likes 0	
Dislikes 0	
Response	
Thank you for the comment, based on industry response the SDT has withdrawn the changes to CIP-014.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
We agree with the retirement of planning based IROLs. We also agree with the	

changes made to the CIP-014 and PRC-023 standards. However we don't agree with the use of a general statement to say that the retirement of FAC-10 will eliminate all planning based SOLs. Planing coordinator can still use their SOLs with valid technical rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Nothing precludes a Transmission Planner or Planning Coordinator from identifying and utilizing SOL and IROL's, the retirement of FAC-010 and the changes in FAC-014 just mean the Transmission Planner and Planning Coordinator is no longer required to identifying or utilize them.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments". The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time. CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.	

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations. Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently. The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support on FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026. Based on industry response the SDT has withdrawn the changes to CIP-014. Due to FERC acting on the Project 2018-03 the SDT has withdrawn changes to FAC-013. The SDT is not making any changes to TOP-001 R22.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
LES supports comments provided by the MRO NSRF related to CIP-014.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support on FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026. Based on industry response the SDT has withdrawn the changes to CIP-014. Due to FERC acting on the Project 2018-03 the SDT has withdrawn changes to FAC-013. The SDT is not making any changes to TOP-001 R22.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP continues to have concerns regarding 4.2.2, Transmission Facilities, within FAC-003. Proposing new requirements in FAC-014 to ensure a Transmission Planner is performing a “planning assessment” does not automatically ensure such efforts will naturally flow to FAC-003 simply because they are in the same standard family. The SDT may be making some assumptions regarding communication in that regard. It should not be assumed that communication between a Transmission Planning function and a Transmission Owner (a Forestry department, for example) would be a naturally occurring activity. If these changes are indeed pursued, the SDT will need to give consideration on how to ensure this communication is taking place. It should also be noted however that while more insight is needed on ensuring this communication takes place, care should also be taken to ensure no restrictions or limitations be unnecessarily placed on the parties involved.

These proposed revisions could unintentionally lead to a line not being properly identified. Any planning event causing instability that is identified in planning assessments, whether the contingency is above or below 200 kV, would have a corrective action plan which may possibly include generation redispatch. If generation redispatch is applied in the operation time-frame, as might be assumed in planning, there is no instability for a planning event and no lines will be identified. We are not certain whether or not the SDT realizes this could be applicable to CAPs of any nature. Could the SDT provide insight as to whether these proposed revisions are requiring that the identification of lines below 200 kV take place pre-CAP or instead post-CAP? In any event, we disagree with the proposed revisions, which we believe changes from identifying lines in a practical way, to doing so in a less practical manner using planning studies.

As stated in the previous comment period, we believe additional text is needed here to ensure no lines are unintentionally excluded by a) the timing of their being identified as part of an IROL and b) the timing of any facilities identified, which could lead to instability, Cascading, or uncontrolled separation within associated planning assessments. The SDT’s response from the previous comment period gives the impression that they may possibly be unaware of the guidance provided in the original Errata which was eventually incorporated into the GTB. The team provided an example of a line identified as an IROL and then incorporated into FAC-003 and that "it could be months or years before the vegetation management caught up with the designation, providing no practical benefit." The SDT may wish to further review the GTB of this standard to ensure they are aware such guidance has already been provided in this standard regarding how soon after a line is identified that it becomes incorporated into the vegetation management program. With this in mind, AEP once again recommends that this section be clarified in the following manner… *"Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation* ***<u>or overhead transmission line operated below 200kV that have been established as part of an IROL by the Reliability Coordinator per IRO-014-3 R1.</u>****"*

Proposed Implementation Plan: The changes proposed are very expansive and involve many individuals across a number of Functional Entities. In addition, new cross-functional procedures and processes would need to developed and established to meet the proposed obligations. As a result, we believe 36 months would be more appropriate.

We believe the references to planning events in CIP-14 Applicability Section 4.1.1.3 and FAC-003 Applicability Sections 4.2.2 and 4.3.1.2 could be more clearly stated. We recommend that CIP-014 Applicability Section 4.1.1.3 be revised to state "Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator, or Transmission Planner, per its Planning Assessment of the NearTerm Transmission Planning Horizon as Facilities that if lost or degraded *due to planning events* are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System."

AEP would like to make a suggestion and encouragement regarding how the standards drafting team provides redlined documents for industry review. While redlined documents using the previously proposed revision as a baseline do provide a very beneficial way for the reader to identify only the most-recently proposed changes, we believe that they cannot be the only redlined document provided during these comment and balloting periods. These particular redlines are simply a "delta" between the current and previous draft revision and do NOT show all the proposed additions and deletions that have been retained-to-date. This could result in the reader misunderstanding or misinterpreting the content in the draft. For example, text shown in black could be a) text currently included in the version under enforcement or b) new text that was proposed in a previous comment period but "no longer considered new text" in the current comment period. In addition, text shown as deleted could be a) text that has been newly proposed for deletion in the current comment period or b) text that was proposed for addition in a previous comment period draft but then later struck from consideration in a latter comment period.

As a result, when multiple revisions are proposed over time, the reader would have to review each and every draft proposed to date and somehow determine for themselves all the changes retained to date. A balloter is not voting on only the most recently proposed changes, they are voting on all the proposed changes that have been retained-to-date. As a result, we recommend drafts showing only most recent changes also be accompanied by an additional redlined document which shows *all the proposed revisions retained to date*, and using the version under enforcement as a baseline.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. With regard to communicating identified facilities by the Planning Coordinator and Transmission Planner, FAC-014 R8 requires that notification. Regarding the pre-CAP or post-CAP question, that is a good point that the Planning Coordinator and Transmission Planner should be aware of and the SDT believes FAC-014 R8 and TPL-001 have enough flexibility for the Planning Coordinator and Transmission Planner to make choices regarding the pre or post dispatch status. The SDT appreciates your comments regarding the inclusion of Reliability Coordinator IROL. The currently in effect FAC-003-4 specifies only the Planning Coordinator and the SDT continues to believe that the Planning Coordinator, and now Transmission Planner, are the correct entities for this standard. Nothing precludes a Reliability Coordinator from reaching out to coordinate their IROLs with the Planning Coordinator and Transmission Planner studies and capture those facilities, if appropriate. The Implementation plan was extended the 24 Months in response to industry comments. The SDT has withdrawn the changes to CIP-014 based on industry comments. The SDT also agrees that providing additional review documents that include a redline against the currently in effect documents would aid in the evaluation of standard changes.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro agrees with the changes to CIP-014, FAC-003, FAC-013 and PRC-023. However, on FAC-013, PRC-023 and PRC-026, BC Hydro offers the following comments and suggestions. **FAC-013-3** Project 2018-03 Standards Efficiency Review Retirements drafting team recommended the retirement of FAC-013-2. As stated in their June 7, 2019 petition to FERC, NERC determined that the standard is not needed for BES reliability, and should therefore be retired. BC Hydro suggest that a revision of FAC-013-2 is no longer warranted. **PRC-023-5** Through the inclusion of the Transmission Planner (TP) in Attachment B, Criterion B2, the proposed revision indicates TP's responsibilities of selecting the circuits subject to requirements R1 through R5. BC Hydro recommends that the TP functional entity be included in the Applicability section of the standard and the TP's responsibilities clarified in the language of the requirement. **PRC-026-2** Requirement 1 mandates that the Planning Coordinator (PC) use Near-Term Planning Assessment results to identify stability constraints associated BES elements. However, the Near-Term Planning Assessment would be conducted by Transmission Planners (TPs) and coordinated by their PC. If a TP fails to provide its PC the list of stability related BES elements, PC could be held non-compliant to PRC-026-2. The proposed draft does not identify the Transmission Planners (TPs) as a responsible entity. BC Hydro recommends that the Transmission Planner's role to timely provide its PC with the BES Elements meeting R1 criteria be reflected within the requirement, and TP functional entity be added to the Applicability section of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Due to FERC acting on the Project 2018-03 the SDT has withdrawn changes to FAC-013. For PRC-023-05 criteria B2 applies to what the Transmission Owner, Generator Owner and Distribution Provider must do if the facility is identified by the Transmission Planner. The standard does not require the Transmission Planner to do anything directly and therefore the Transmission Planner would not be part of the Applicability. Regarding PRC-026-2 the Transmission Planner and Planning Coordinator are both responsible for conducting a TPL Assessment. Certainly in some areas of North America the Planning Coordinator may be utilizing material from their Transmission Planner and in other areas the	

Transmissions Planner is utilizing information from their Planning Coordinator to meet that requirement. However both are ultimately required to fully meet TPL-001, so the Planning Coordinator can be expected to have the information without the need for additional requirements.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports MRO NSRF comments. The MRO NSRF agrees with the changes to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 (subject to the recommendations made in questions 1 to 6), but disagrees with changes to CIP-014 at this time.	

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

The MRO-NSRF suggests the SDT coordinate with Project 2018-03 which shows FAC-013 and TOP-001 R22 scheduled to be retired by FERC.

Likes 0	
Dislikes 0	

Response

Please see the response to MRO NSRF.

Anthony Jablonski - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

ReliabilityFirst offers the following comments for consideration.

1. PRC-026-2

    i. The revised Standard uses the capitalized term “Near-Term Planning Horizon,” but this term is not in the NERC Glossary. The term defined in the NERC Glossary is “Near-Term **Transmission** Planning Horizon.”

    ii. The revised Standard uses the capitalized term “Near-Term Planning Horizon” but this term is not in the NERC Glossary.

2. PRC-023-5

   i. Attachment B criteria B2 added the term in bold: "… instances of instability, Cascading, or uncontrolled separation, **that adversely impact the reliability of the Bulk Electric System** for planning events." The bolded term is also used in FAC-011-4, and our comments are nearly the same: What is the meaning of "that adversely impact the reliability of the Bulk Electric System?" Is it possible for instability, Cascading, or uncontrolled separation to NOT adversely impact the reliability of the BES? What is the criteria for determining if instability, Cascading, or uncontrolled separation do or do not adversely impact the reliability of the BES? Attachment B criteria B2 is open to interpretation, and therefore does not promote the reliability of the BES. Note that the NERC approved definition of IROL also uses the term "… that adversely impact the reliability of the Bulk Electric System."

   ii. There are references in R6 to version 4 of the Standard (PRC-023-4) that should be changed to reference the new PRC-023-5 Standard

   iii. Recommend update to the new format with the measurements placed under each requirement.

3. FAC-003-5

   i. While RF disagrees with the removal of IROL lines as a whole due to reduction of lines falling under the compliance standards regarding maintenance, the noted red-lined changes are recommended for approval as stated.

4. CIP-014-3

   i. For all these, references to planning events needs to be more clearly stated as being the planning events in TPL-001 Table 1.

CIP-014-03 R4.1.1.3 **This needs to be made clearer. I am reading this revision in several different ways, none of which I believe to be then intent of the change. I think the reference to planning events needs to be changed to single station or single station location event.**

Here are the two ways that I read the standard as proposed. 1) What are the planning events? Are they the subset of TPL-001 Table 1 P1 through P7 events that could cause the loss of the single station or substation location, or all facilities at a single voltage level in a station or substation? If so, the CIP standard should provide more detail on what assumptions must be made for the planning events, that differ from the same events when studied per TPL requirements. 2) Are the planning events additional contingencies after system adjustments, and with the single station or substation still out of service? If so, this is a significant change the severity of events that this standard addresses. Is this a requirement to study the station outage concurrent with a planning event?	
Likes 0	
Dislikes 0	
Response	
The Drafting team revised PRC-026-2 to correct the use of the "Near-Term Transmission Planning Horizon" term. For PRC-023-5 The Planning Coordinator or Transmission Planner would make a determination based on their study results of what *"adversely impacts the reliability of the Bulk Electric System"* based on their criteria specific to their system. This provides a study results based outcome that is clear and measurable based on their criteria, and is specific to the Planning Coordinator and Transmission Planners system. FAC-003, PRC-002, PRC-023 and PRC-026 all contain criteria to determine what facilities require the higher level of protection and do not apply as a blanket to all facilities. Including the caveat of *"adversely impact the reliability of the Bulk Electric System"* maintains that filtering of only those facilities that require that higher level of protection. The caveat does not preclude the Planning Coordinator or Transmission Planner from considering all instability, Cascading or uncontrolled separation to be adverse to the reliability of the Bulk Electric System, but it does allow them to exclude those elements that based on their criteria and system conditions are not adverse to the reliability of the Bulk Electric System and don't merit the higher level of protection. The SDT also reviewed the document and fixed the incorrect references, thank you for identifying it. Updating the standard format is not within the scope for the current project.	

FAC-003-5: Thank you for your comment

CIP-014-3: Based on industry response the SDT has withdrawn the changes to CIP-014.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion has the same concerns with the term instability that we have previously shared both here and in regards to prvious versions of CIP-002. The current use of the term, without clarification that it is intended to be applied to wide area issues, could lead to misinterpretation of the intent and lead to inconsistent application of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT is not revising the CIP-002 standard at this time.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
BHE does not agree with the changes to CIP-014 **BHE agrees with the changes to FAC-013**	

BHE agrees with the changes to PRC-002

BHE agrees with the changes to PRC-023

BHE agrees with the changes to PRC-026

BHE agrees with EEI's response to this question. The EEI response conveys that the proposed changes to the CIP-014 Aplicability Section would break the alignment between CIP-014 and CIP-002.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments, based on industry response the SDT has withdrawn the changes to CIP-014.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Some changes seem to be minor and some require revisiting the methodology and more coordination. Unless there is a fatal flaw with the existing, the proposed changes create a more complicated process that impacts several Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The changes were needed to address the changes to FAC-010, FAC-011 and FAC-014	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	No
Document Name	
Comment	
OGE has similar concerns expressed by MRO-NSRF on CIP-014 changes. The proposed CIP-014 change would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014. OGE recommends the SDT to ensure any changes made to CIP-014 conforms with CIP-002.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Thank you, please see the NSRF Response.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy disagrees with the proposed changes to CIP-014 as the changes proposed are not also being applied to NERC Reliability Standard CIP-002 - Attachment 1, criteria 2.6. The four (4) sub-parts of Applicability Section 4.1.1 in the current approved CIP-014 standard are based on a subset of the NERC CIP-002 Attachment 1 criteria. The proposed change to CIP-014 section 4.1.1.3 would bring inconsistency with the CIP-002 - Attachment 1, criteria 2. While we do not necessarily oppose the proposed revision, the SDT should also ensure the change is made to CIP-002 for consistency and the proposed changes would need to be more carefully considered for impact within the CIP-002 standard before we can fully support.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014 and is not changing CIP-002.	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	

Response	
Please see the response to the MRO NSRF.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC Supports the comments of the MRO NSFR and EEI.

CIP-014 Applicability Section 4.1.1.3 comes from CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 considered and rejected this proposed change for CIP-002-6, which just passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and sundering the connection to and synergy with CIP-002, creating disparate populations.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments please see the responses to MRO NSFR and EEI. Based on industry response the SDT has withdrawn the changes to CIP-014.	

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	No
Document Name	
Comment	
Oncor supports the comments submitted by EEI for CIP-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp does not agree with the changes to CIP-014 and supports EEI and MRO NSRF with their comments. The CIP-014 Applicability Section 4.1.1.3 comes from language in CIP-002-5.1a Medium Impact Rating criterion 2.6. The SDT for Project 2016-02 filed CIP-002-6 with FERC for approval, which passed industry ballot without any change to criteria 2.6 and 2.9, both of which continue to reference IROLs, a NERC Glossary-defined term.	

The proposal would lower the threshold from Interconnection instability to any instability affecting the BES, representing a potentially substantial increase in scope for CIP-014, and changing the connection and synergy with CIP-002.

Deference should be given to the SDT for Project 2016-02 with respect to any conforming changes to CIP-002 and CIP-014, which need to be addressed concurrently and consistently.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned with removing the Reliability Coordinator (RC) in the applicability of proposed CIP-014-3. The RC, as specified in the proposed FAC-014 standard, establishes Interconnection Reliability Operating Limits (IROLs) in accordance with its SOL methodology. Once identified in the operational horizon, however, the RC will likely adopt more conservative operational criteria to avoid instability, Cascading or uncontrolled separation. As Texas RE reads the current FAC-014 requirements, the Planning Coordinator (PC) and Transmission Planner (TP) will be required to plan using at least these more conservative Facility Rating, voltage limits, and stability criteria. The use of these more conservative limits in the Planning Assessment could potentially make it less likely that the TP and PC will ultimately identify instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System. As such, facilities currently subject to the CIP-014 requirements today would be potentially excluded from the scope of the proposed CIP-014.

Texas RE understands that the SDT's intent in revising the CIP-014 was not to change the substantive scope of the CIP-014 requirements. To ensure there is no inadvertent changes to the facilities subject to CIP-014, Texas RE recommends that facilities identified by the RC as causing instability, Cascading, or uncontrolled separations that adversely impact the reliability of the Bulk Electric System be retained in the scope of the CIP-014 requirements.

Texas RE has the following comments regarding proposed FAC-003-5:

- It is unclear how planning events that involve multiple elements (e.g. TPL-001-4 P6 event) would fall into the applicability of FAC-003-5. The applicability section of FAC-003-4 made it clear using the language of "Each overhead transmission line operated below 200kV identified as an element of an IROL…" FAC-003-5, however, simply uses the language "a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event." It is not clear whether each element that comprises the planning event or only a single line "that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System".
- The asterisk on Table 2 appears to be inconsistent with FAC-014. The asterisk is applicable only "if PC has determined such per FAC-014." FAC-014 includes both of the PC and TP in Requirements R6-R8. The footnote as written excludes the TP so it is unclear whether TP Facilities, determined per FAC-014 R8, are subject to vegetation management. This could leave a gap in the reliable operations of the grid if the list of Facilities derived by the PC and TP are different. Texas RE recommends adding "and TP" to the footnote in FAC-003-5.

Texas RE noticed that the rationale for PRC-002-3 includes a reference to PRC-002-2 in Requirement R6. The Guidelines and Technical Basis Section also contain references to PRC-002-2 (e.g. Introduction Section, Guideline for Requirement R6, R7).

Texas RE has the following comments for proposed PRC-023-5.

Texas RE recommends Transmission Planner be added to Requirement R6 and the Applicability section of the standard. In section 4.2 Circuits, there are references to the lines selected by the Planning Coordinator in accordance with Requirement R6. Requirement R6, with the Planning Coordinator as the only functional entity type listed, references Attachment B of PRC-023-4. Attachment B contains an addition in

B2 regarding the Transmission Planner selection of a circuit. As stated in the "Criteria" section of Attachment B: "If any of the following criteria apply to a circuit, applicable entity must comply with the standard". If Transmission Planner is not included, there could be a gap in the reliable operations of the grid if the list of circuits selected by the Planning Coordinator and Transmission Planner are different.

- Requirement R6 contains references to PRC-023-4 Attachment B (and Measurement M6 has similar reference.), which needs to be updated to PRC-023-5.

Texas RE has the following comments for proposed PRC-026-2.

- Texas RE requests the SDT consider capitalizing Transmission Line in Section A 4.2, Requirement R1, and Part 2.2 since it is a defined term.
- Texas RE requests the SDT to provide more clarification regarding the term "planning event". Texas RE recommends stating that the planning events refer to Table 1 in TPL-001. As written, registered entities could make their own definition of what a "planning event" is and that definition may not cover all TPL-001 events listed in Table1.

Texas RE has the following comments for the White Paper.

Texas RE inquires as to which definitions are being proposed. The white paper contains a revised definition of System Operating Limit. There is also a definition of System Voltage Limit posted for a different project phase. Texas RE recommends putting the definitions in the implementation plan so it is clear what is being proposed.

- Please ensure consistency with the standards with regards to capitalizing NERC Glossary Terms. For example, "Steady State" is capitalized and it is not a NERC Glossary term.

- On Page 3, there is nothing after i. Part 6.1.3
- “Real-time Monitoring” is capitalized in bullet 5 on page 5, bullet 2 of page 7, and bullet 6 of page 7. Real-time monitoring is not a defined term in the NERC Glossary and should not be capitalized.
- On page 4, Texas RE recommends using the language of the standard to describe the intent of the SOL concept within FAC-011. Texas RE recommends revising number 1. to “Facility Ratings, System Voltage Limits, and the stability performance criteria noted in R4”.
- criteria noted in R4”.
- On page 6 there is a discussion about maintaining SOL performance that includes a reference to “associated time parameters” for System Voltage Limits. As discussed previously, there is no time requirement stated within the definition of System Voltage Limits and therefore clarity is needed to implement the standards using System Voltage Limit and referencing a time duration.
- On page 6, Texas RE recommends revising “unit stability” to “angular stability” to match the Standard.
- On page 6, “Stability” should not be capitalized in the last sentence as it is not defined in the NERC Glossary. “Stability” is capitalized in the discussion about Voltage Stability Limits as well.
- Number 3 on page 6 references TOP-001-3. Since this project is proposing TOP-001-6, Texas RE recommends revising it to TOP-001-6.

Likes 0	
Dislikes 0	

Response

CIP-014: Based on industry response the SDT has withdrawn the changes to CIP-014.
FAC-014: The existing FAC-003 used Planning IROL’S which based on FAC-010 included basically the same single element, common element and multiple line events as covered by the “planning events” in the current TPL standards. The Planning Coordinator and Transmission Planner have some discretion in determining what planning event contingencies adversely impact the reliability of the BES. Part of that discretion would be deciding which P6 events – if any – are adversely impacting the reliability of the BES and from those P6 events what contingencies would cause the impact. For a P6 event it may be both contingencies, the first contingency, or the second contingency, depending on the severity of the system response and the impact each contingency has on the system.

FAC-014: Thank you for pointing out the asterisk. Given the asterisks were redundant with the applicability section the SDT removed the asterisks from the tables to avoid confusion.
PRC-002: The team has reviewed PRC-002 to make sure any references are correct.

For PRC-023-05 criteria B2 applies to what the Transmission Owner, Generator Owner and Distribution Provider must do if the facility is identified by the Transmission Planner. The standard does not require the Transmission Planner to do anything directly and therefore the Transmission Planner would not be part of the Applicability. The Reference to PRC-023-4 in R6 and M6 has been corrected, thank you for noticing.

For "transmission line" in PRC-026, the term is used multiple times throughout the existing document and the "t" is consistently not capitalized. The SDT doesn't believe capitalization would improve clarity and is therefore not a necessary change at this time.
The Term "planning event" in PRC-026 refers a class of event that may have been identified in the "Planning Assessments of Near-Term Transmission Planning Horizon" and triggered the other conditions listed in Criteria 1, 2 and 4. This is to distinguish those events from extreme events with the Planning Assessment that might also have met the criteria. The reference is therefore not to the entire body of Planning Events in Table 1 of TPL-001 but instead to those events studied as part of the Planning Assessment and that triggered Criteria 1,2 or 4.
Thank you for the comment revised white paper, the SDT considered each of your comments and applied them where appropriate.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
A common language has been utilized to revise these standards stating "that adversely impact the reliability of the BES". This language does not detail what is considered "adverse impact," and therefor introduces inconsistencies among the industry.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The term “adversely impact the reliability” is currently in use for the IROL definition and has been successfully applied by the industry for many years resulting in varied applications that are tuned for the topology and characteristics of the BES in their area. The building codes across North America vary based on the conditions expected in those areas, with the consistent goal of having the buildings be safe and energy efficient but differences in execution. By the same measure the objective is consistent, avoiding adverse impacts to reliability, but the measures or methods applied must be specific to the area it is being applied since the power system in North America is not homogeneous. When the industry adopts a revised IROL definition that provides greater specificity or a different description than “adversely impacts the reliability” the SDT agrees these sections should be reviewed for conformity at that time and revised if needed as part of that project.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

Comments: AZPS supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014.

AZPS supports EEI’s comments that changes made to CIP-014 are not necessary and these changes could have unintended consequences for the industry. Similar changes were proposed under Project 2016-02 and industry rejected the changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term ‘instability’, within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term ‘instability’ is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber

assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets. In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term “instability” to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact. Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry back in 2018 for CIP-002 remains unchanged. For this reason, we ask the SDT to not break the linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) creating unnecessary confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to EEI.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
PRC-002 - TVA disagrees with the proposal to change responsibility for PRC-002-3 R5 from the Planning Coordinator (PC) to the Reliability Coordinator (RC). We believe the responsibility for determining the need for DDR equipment should remain with the PC as this is better evaluated in the near-term planning horizon.	

FAC-003 - On page 9, we recommend adding "…for a planning event" to the Category 1A description for consistency with the edits made for Category 1B, 2A, 2B, 4A and 4B.

CIP-014 - We agree with comments provided by several other entities regarding the proposed change to applicability section 4.1.1.3 creating a misalignment with CIP-002 - Attachment 1, part 2.6.

Likes 0	
Dislikes 0	

Response

PRC-002 – The SDT team disagrees and believes that the responsibility should be with the RC who is responsible for any event investigation, however that doesn't preclude input from the Planning Coordinator on DDR placement.

FAC-003: Thank you for noticing, we have made that change to FAC-003.

Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 7.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see the response to EEI's comments.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energys supports the following comments provided by EEI:

EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT:

The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term "instability" to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact.

Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see the SDT response to EEI's comments.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	

Comment	
Please consider not revising CIP-014, at this time. The revision of CIP-014 applicability section 4.1.1.3 will be inconsistent with CIP-002 Attachment 1 – Impact Rating Criteria 2.6. This could lead to uncertainty regarding applicability and impact ratings. We suggest that CIP-014 and CIP-002 should be revised at the same time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the changes made to FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026 but do not support the changes made to CIP-014. Similar changes were proposed under Project 2016-02 and the industry rejected those changes in 2018. At that time, EEI offered the following comments to the Project 2016-02 SDT: The use of the term 'instability', within the context of Criterion 2.6, represents a potential point of confusion, because it could be interpreted as increasing the scope for CIP-002-6. While the term 'instability' is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has been limited in scope to specific reliability impacts to the Bulk Electric Systems. However, the proposed language in Criterion 2.6 does not impose similar limits and could be interpreted to mean entities need to reclassify many cyber assets to medium impact. Additionally, BES generator reclassified under the medium impact criteria that also have a Control Center within the physical boundaries of that facility would now become a high impact BES Cyber Assets.	

In order to remedy this concern, EEI suggests that the SDT consider language similar to what is currently used in the GTB for Criterion 2.9 which ties the term “instability” to Wide Area impacts. This would be consistent, in approach, with the scope of CIP-014 by limits the scope of instability to a defined area of impact. Ultimately the Project 2016-02 SDT reverted to the original language. Additionally, the concern expressed by the Industry in 2018 for CIP-002 remains unchanged. The linkage between CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
The changes made to the Applicability Section of CIP-014 no longer align with CIP-002. We also note that the proposed changes to PRC-023-3 and PRC-026-2 referring to Planning Assessments no longer correspond to the language in PRC-002-3 which does not refer to Planning Assessments but refer to BES Elements that are part of an Interconnection Reliability Operating Limit (IROL) [Requirement R5, Part 5.1.4 as well as in the Guidelines and Technical Basis Section, Guideline for Requirement R5]. The use of the term ‘instability’ in CIP-014-3 represents a potential point of confusion. While the term ‘instability’ is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, while it is used in TPL-001-5.1 in the context of identifying “System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding” as defined and documented by each Transmission Planner and Planning Coordinator within their Planning Assessment.	

There are also (minor) inconsistencies in the wording referring to identifying Facilities per Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, e.g., "planning events" in CIP-014-3 and PRC-023-3 vs. "a planning event" in FAC-003-5 and PRC-026-2 as well as variations in the wording related to the above reference to results from Planning Assessments in the sub-bullets of Requirement R1 of PRC-026-2. Please consider using consistent wording. In addition, please consider an alternate approach for revising the Applicability criterion in Part 4.1.1.3 of CIP-014-3 such as: "Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." This is essentially the same criterion as in CIP-014-2 without including the Planning Coordinator or Transmission Planner functional entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not support adjusting the applicable entity in PRC 002 [R5] from TP/PC to RC for the Eastern Interconnect. TP/PCs are appropriately positioned to identify where dynamic Disturbance recording (DDR) data is required based upon their wide area view of reliability needs, particularly as it pertains to changing system conditions that can be best gauged in the near term planning horizon. Furthermore, this time horizon is more aptly suited for determining equipment installation requirements due to the lead-time associated with the installation of any BES equipment. Lastly, there are potentially significant implementation plan and timing concerns with shifting the	

applicability of existing requirements to another functional entity, that could correspondingly shift the location and amount of DDR coverage required. These implementation considerations would need to be addressed.	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
PRC-002 – The SDT team disagrees and believes that the responsibility should be with the RC who is responsible for any event investigation. The Implementation Plan provides 6 months for the RC top pick up the responsibilities in R6 which given the requirements have not changed from the PC's work should result in identical placement unless there are places where the RC and PC have had a difference in opinion on DDR placement or SOL Determination. Nothing precludes the RC from using the prior work of the PC and coordinating with the owners to minimize the relocation of devices.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
For each of these standards, the intent of this project was to replace the term IROL with the definition of an IROL. In doing this, the SDT also added Transmission Planner to the requirements. In the original standards, the requirements were for the Planning Coordinator to identify the IROL. This work was assigned to the Planning Coordinators as they have a global view of the interconnected transmission systems. While Transmission Planners do perform stability studies, it is the Planning Coordinators that have this overarching view of the interconnecting systems when they perform their studies, thus it should remain only the responsibility of the Planning Coordinator to identify those facilities that are the basis for these standards in stability violations equivalent to an IROL.	

ITC requests the SDT clarify the term Planning event with additional clarifying information. If the intent was for the contingencies to include the P0-P7 Planning event, clarify by using this terminology or be very explicit to identify that extreme events are not included. This clarification is requested in PRC-023 and PRC-026.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The area of their responsibilities and depth of analysis varies between different parts of North America with regard to PC and TP, the SDT believed that the Transmission Planner should also be able to identify those facilities that meet the definition of IROL and not just the PC. This is does not relieve the PC of the responsibility, it just insures that the TP can also bring forward a facility that is perhaps too local in nature for the PC to identify – but still could adversely impact the reliability of the BES and therefore meets the definition. The Term "planning event" in PRC-023 and PRC-026 refers a class of event that may have been identified in the "Planning Assessments of Near-Term Transmission Planning Horizon" and triggered the other conditions specified in PRC-023 and PRC-026. The term "planning event" is consistently used in TPL-001 to refer to those events listed in Table 1 as planning events and the SDT doesn't believe further clarification is required within PRC-023 or PRC-026.	
Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see the SDT response to EEI's comments.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	
Comment	
A common language has been utilized to revise these standards stating "that adversely impact the reliability of the BES". This language does not detail what is considered "adverse impact," and therefor introduces inconsistencies among the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The term "adversely impact the reliability" is currently in use for the IROL definition and has been successfully applied by the industry for many years resulting in varied applications that are tuned for the topology and characteristics of the BES in their area. The building codes across North America vary based on the conditions expected in those areas, with the consistent goal of having the buildings be safe and energy efficient but differences in execution. By the same measure the objective is consistent, avoiding adverse impacts to reliability, but the measures or methods applied must be specific to the area it is being applied since the power system in North America is not homogeneous. When the industry adopts a revised IROL definition that provides greater specificity or a different description than "adversely impact the reliability" the SDT agrees these sections should be reviewed for conformity at that time and revised if needed as part of that project.	

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	
Comment	

Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the SDT response to the MRO-NSRF comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see the SDT response to EEI's comments.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA endorses the MRO-NSRF comments regarding the Implementation Plan being too short for the necessary adjustments and training.	

as for the rest:

WAPA does not agree with the use of "degraded" in FAC-003-5 or CIP-014-3. Degraded is a concept pertinent to BES Cyber Systems, BES Cyber Assets, Protection System, or RAS meaning that normal functionality is compromised. The term makes sense in the context of Cyber Assets given that their capabilities or availability can be reduced, e.g., slower sample rate of telemetry for protection, loss of high speed communication-aided fault clearing but Zone 2 backup remains intact, induced misoperations or failures to operate, etc. In the context of the establishment of Facility Ratings (FAC-008-3 Requirement R6), degradation is not a consideration. In other words, Facility Ratings are established consistent with a Facility Ratings methodology (FAC-008-3 Requirements R2 and R3) that may typically use normal or expected System configuration as a precondition for determining the Equipment Ratings, of which there is serially-connected most-limiting equipment, that comprise the Facility. Transmission line Normal and Emergency Facility Ratings should already consider ampacity, sag, and conductor temperature rise over ambient, amongst many parameters, when established.

The concept of transmission or generation Facility degradation is difficult to describe because the degraded System state or configuration is ambiguous. Degraded could refer to a myriad of abnormal System states, including: n-X prior outages, flows immediately post-Contingency, congestion requiring market redispatch, off-nominal System inertia due to displacement of conventional spinning mass generation with renewables, etc. Transmission Owners and Generator Owners do not publish reams of Facility Ratings considering every possible degraded state, nor would it be achievable for operating entities to use this information. In fact, take the simple example of Dynamic Line Ratings or Ambient Adjusted Ratings. Firstly, only a minority of North American transmission lines are currently operated with temperature-adjusted Facility Ratings. And, in most cases Transmission Planners and Planning Coordinators employ static Facility Ratings for the purposes of steady-state assessments, only invoking any consideration of temperature adjustment after identifying post-Contingency failures to meet System performance requirements of TPL-001-4 (soon -5) Table 1.

It is a fundamental Facility Ratings concept, reinforced by the Glossary of Terms definition, that Emergency Ratings have an associated duration. Therefore, WAPA disagrees with any approach to a calculated post-Contingency exceedance of a Normal Facility Rating that does not give some consideration of the duration the exceedance may persist before mitigation. Frankly, with the interest in reliability in mind, the SDT should not want to imply Transmission Planners and Planning Coordinators ignoring the headspace between Normal and Emergency Facility Ratings by only considering exceedances of Emergency Facility Ratings appropriate for Corrective Action Plans. To do so would be to plan the transmission system such that Normal Facility Ratings were irrelevant and essentially to state that all Normal Facility Ratings exceedances will be mitigated in the Operations Horizon; which we know to be poor planning and not always possible.

WAPA disagrees that the draft FAC-003-5 Applicability, Part 4.2.2 that infers flexibility that allows the Planning Coordinator or Transmission Planner to judiciously identify “a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.” On the contrary, this is a prescriptive inclusion that obligates the Planning Coordinator or Transmission Planner to perform unique analysis in addition to the requirements of TPL-001-4 (and -5). WAPA hopes that the SDT will remember that TPL-001-4 (and -5) Requirement R2, Part 2.7 requires the Planning Assessment to include Corrective Action Plan(s) addressing how failures to meet System performance requirements will be met; it does not require the Planning Coordinator or Transmission Planner to identify degraded Facilities that may be expected to result in instability, Cascading, or uncontrolled separation.

While annual Planning Assessment practices vary, instances of instability, Cascading, or uncontrolled separation that maybe mitigated by allowable Table 1 Interruption of Firm Transmission Service and/or Non-Consequential Load Loss will likely have no Corrective Action Plan developed and, thus, would not be reported as part of an annual Planning Assessment. WAPA has concerns that the “expected to result in instances of instability, Cascading, or uncontrolled separation” draft language is vague enough to imply that typical annual Planning Assessments that document Corrective Action Plans for instability, Cascading, or uncontrolled separation that are failures to meet System performance requirements of Table 1 will become insufficient. The result, we foresee, is that Transmission Planners and Planning Coordinators will become obligated to document every instance of instability, Cascading, or uncontrolled separation that they observe during analysis supporting their annual Planning Assessment, not just those instances that required Corrective Action Plans.

To summarize our comments:

The use of “degraded” Facilities is vague and should be removed from all proposed instances from FAC-003-5 and CIP-014-3.

The use of “adversely impacts the reliability of the Bulk Electric System” is redundant and should be removed from all proposed instances from PRC-023-5, CIP-014-3, FAC-011-4, and FAC-014-3. WAPA greatly appreciates the time and attention that the SDT has made to each of the Reliability Standards affected by the “raising of the bar” for SOLs. Your work is necessary and relevant! Thank you for the opportunity to provide comment.	
Likes 0	
Dislikes 0	

Response

Implementation Plan: The SDT has extended the implementation plan to 24 months.

In response to industry comments the drafting team has withdrawn the changes to CIP-014.

Specific for FAC -003-5 the SDT was considering “degraded” to refer to a condition were due to vegetation encroachment the facility can no longer reliably and safely operate at its design rating. For dynamic line ratings and ambient adjusted ratings provisions for that would presumably have taken place in the Planning Assessments and since those are part of the facility rating of the facility.

The SDT specifically address the use of the space between Normal and Emergency line ratings in both the standards and the white paper as it directly applies to the RC and TOP. The TP and PC are already required to consider the time limit on any rating above normal and any planned response needs to fit within that time rating by the TPL standard.

The SDT agrees with WAPA that every instance of instability, Cascading or uncontrolled separation, and especially those mitigated by Table 1, would not warrant reporting in the Planning Assessment, or more specifically in this context reporting for the Facility Owner for consideration in FAC 003. That is why the SDT retained the IROL language that states “adversely impacts the reliability of the Bulk Electric System” to narrow that list to only the most critical of events.

In WAPA’s summary, WAPA is requested the removal of the “adversely impacts the reliability of the Bulk Electric System” from the modified standards, however the SDT has the same concern expressed by WAPA in regard to FAC 003 that such removal would expand the consideration to any instability, Cascading or uncontrolled separation, and not every event may warrant escalation, just based solely on the instability, Cascading or uncontrolled separation.

Marco Rios - Pacific Gas and Electric Company - 1	
Answer	No
Document Name	
Comment	

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be further investigated and considered as part of this project:

- The changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be “critical to the derivation of” IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the “instability, Cascading, and uncontrolled separation” language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.
- PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.
- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section

4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:

- "Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18 month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

In response to industry comments the drafting team has withdrawn the changes to CIP-014.

PRC-023 Attachment B Criterion B2 the TP directly informs the facility owner and does not need to notify the PC or provided information into the PC's assessment under PRC -023 R6, those are independent review that create separate lists of facilities that must conform to PRC-023. The TP would make the selection based on the criteria listed in B2 which is the same criteria in place today on the Planning Coordinator under B2, just spelled out as the definition of an IROL rather than using the term IROL. Keep in mind the B2 and PRC-0234 do not obligated the TP to take this action, it only obligates Facility Owner to react if the TP identified a facility.

FAC-003 today does not exempt WECC utilities from having a sub 200kV line being identified as part of an IROL, and the revised language removes the term IROL, but inserts instead the definition of the IROL and the PC and TP Planning Assessment as a means of identifying those IROL-like facilities instead of the FAC-010 methodology.
FAC-003 R6 currently requires inspections once per calendar year, and allows to a limited extend (18 months) more than a year to pass between inspections. The measure is crafted using the same language so the SDT is unclear on the benefit of modifying the measure and not the requirement. Additionally this particular requirement and measurement pair is not directly within scope nor in the body of administrative corrections the team has incorporated into the standard.
FAC-014-3 R8 was put in place to insure that the PC and TP communicated information that TO and GO may need to conform to existing standard, addressing an existing current gap that did not require that communication. The addition was not intended to replace PRC-026 R1. PRC-026 R1 specifically refers to angular stability constraint, an angular instability or relay tripping due to power swings which is different list of criteria, though at times overlapping, than what is referenced in the proposed FAC-014-3 R8. PRC-026 then specifically references R1 as the facilities that need to be considered for the steps identified in PRC-026. Replacing PRC-026 with R1 may result in some facilities not being identified, and the identification of facilities that wouldn't benefit from the PRC-026 requirements.

Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Connditionally Yes - Request clarification of the phrase “adversely impacts” for impacted Standards. For example, the first FAC-003 instance reads: 4.3.1.2 Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that "adversely impacts" the reliability of the Bulk Electric System for a planning event… Please confirm the phrase “adversely impacts” has the exact meaning as the NERC Reliability Standards Glossary defined phrase “Adverse Reliability Impact”; if different, please define phrase "adversely impacts".

Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The term “adversely impacts” as well as the rest of the IROL Definition replaces the term IROL within the standards when it refers to the TP and PC Planning Assessment since the retirement of the FAC-010 removed the obligation for the TP and PC to identify IROL’s. The industry has been successfully operated the system reliably with this term in place for the determination of IROLs for many years with further refinement being done on a system by system basis in response to the unique characteristics and needs of each part of the BES. If the future effort to revise the IROL definition modifies this term then these subsequent standard should also be evaluated to see if the new definition for IROL can be incorporated. The IROL definition and the SDT’s work does not capitalize the term “adversely impact” and so does not directly tie it to the NERC Standard Definition of Adverse Reliability Impact, however that doesn’t preclude the use of the NERC Definition as an entities definition of “adversely impact”. The SDT also extended the implementation period from 12 months to 24 months.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment	
PPL NERC Registered Affiliates support the proposed revisions to FAC-003. However, the revised language is somewhat ambiguous, and we would appreciate the Drafting Team providing clarification on how the revisions apply to lines under 200kV described in 4.2.2. The conditions described in the revised FAC-003 affecting lines under 200 kV would not occur without being in violation of planning requirements of TPL-001-5 and TPL-001-4, which require looking to the future and mitigating where a single outage may result in a stability issue.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees that the list of facilities identified under TPL-001 Planning Assessment should be limited given that the Planning Assessment encourages planning the future system to avoid those constraints, and many TP and PC Planning Assessments may identify no facilities that qualify. As an example only, a facility identified could be an emerging condition that does not meet the TPL criteria and as a result has a corrective action plan being implemented to bring them into conformance and the identification of those facilities under FAC-003 affords additional protection to system reliability until the corrective action plan can be completed.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
With regards to standards revisions or deletions to FAC-010-3, FAC-011-3, and FAC-014-2 requirements for determining and communicating SOLs used in the reliable planning and operation of the BES, BPA agrees with the associated changes to FAC-003, FAC-013, PRC-002, PRC-023, and PRC-026. Regarding CIP-014-3, it is unclear how the Planning Assessment performed by the Planning Coordinator or the Transmission Planner in Applicability criteria 4.1.1.3 relates to the risk assessment performed by the Transmission Owner in Standard Requirement R1.	

BPA suggests the following edits to criteria 4.1.1.3 to help clarify. 4.1.1.3. “Transmission Facilities that are identified by the Planning Coordinator or Transmission Planner through its Annual Planning Assessment of the Near-Term Transmission Planning Horizon, at a single station or substation location that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion CIP-014 part 4.1.1.3 (Applicability Section) and CIP-002-5.1a (Attachment 1, Criterion 2.6) should remain to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes

Document Name	
Comment	
Hydro-Québec Production agrees with the changes to PRC-002. We are not impacted by the other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Oncor supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see the SDT response to EEI's comments.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:	

Requirement R6 and 6.1 of the draft PRC-023-5 continue to reference PRC-023-4 Attachment B. Wondering if that's intentional or an oversight which should reflect version 5 instead of 4 of PRC-023? Additionally, the Implementation Plan still references PRC-023-4 instead of PRC-023-5 and should be reviewed due to a spelling error of "its" on page 4 following *conduct* and prior to *first assessment* that should be corrected.	
Likes 0	
Dislikes 0	
Response	
Please see the SDT response to the ISO/RTO Counsel Standards Review Committee Comments. PRC-023 has had all its internal references updated for the final posting thank you for noticing that error. The Implementation plan has been reviewed and all references corrected. The reference to PRC-023-4 in "additional provisions" is intentional and meant to clarify that the next assessment cycle for PRC-023 should pick up the new version and that the past assessment under version 4 continues to be valid until its normal expiration date.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	

The Standard Drafting Team should review the proposed changes and fully consider all implications of changes to other standards. Below PG&E identifies a few instances that should be furthe investigated and consideed as part of this project:

- For example, the changes to CIP-014 are concerning with this Project. Section 4.1.1.1 (all facilities 500 kV or higher) and Section 4.1.1.2 (weighting criteria comparable to other CIP standards) previously worked together with Section 4.1.1.3, which served as an exception to include additional facilities determined to be "critical to the derivation of" IROLs in the CIP-014 studies. Now, the language has removed the engineering judgment and requires ALL facilities from the Near-Term TP Assessment meeting the "instability, Cascading, and uncontrolled separation" language to be included in the CIP-014 studies, without any judgment applied. The language in 4.1.1.3 must be enhanced to ensure that only outages with severe system impacts.

- Another example is PRC-023 Attachment B Criterion B2, in which the TP has now been added to the PC as another entity that can designate possible facilities to be evaluated for Transmission Relay Loadability. However, the PC is required to perform an assessment in R6 of this standard to determine a required circuit list, but the TP has no such requirement. There are no other details provided to the TP describing how a such selection would/should occur and be communicated to the PC, which could lead to issues with compliance.

- The proposed changes to FAC-003, does not clearly state that Section 4.2.2 (each overhead transmission line operated below 200kV identified as an element of an IROL under FAC-014 by PC) applies to non-WECC utilities. Conversely, PG&E would be subject to Section 4.2.3 (each overhead transmission line operated below 200kV identified as an element of a Major WECC Transfer Path in the BES by WECC) which is clearly applicable to PG&E. It would also be useful to remove the strike-through text in M6 listed below:

"Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records."

- The reason for this recommendation is that the current language can be confusing and provides no value. The months leading up to and following the beginning and end of a calendar year (i.e. December and January) fall outside of the growing season. Moving to an 18-month window regardless of calendar vastly simplifies the requirement for both the Utility Company and the Regulator.

- In PRC-026 R1 the PC has reporting requirements to the TO and GO which have been updated as part of this effort. How do these requirements mesh with FAC-014-3 R8, since there appears to be some overlap in the requirements? Does it make sense to continue to have these similar reporting requirements in separate standards?

It appears that some of proposed changes to these standards could use additional scrutiny to ensure that there are no unintended consequences of these changes.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Based on industry response the SDT has withdrawn the changes to CIP-014.

PRC-023 Attachment B Criterion B2 the TP directly informs the facility owner and does not need to notify the PC or provided information into the PC's assessment under PRC-023 R6, those are independent review that create separate lists of facilities that must conform to PRC-023. The TP would make the selection based on the criteria listed in B2 which is the same criteria in place today on the Planning Coordinator under B2, just spelled out as the definition of an IROL rather than using the term IROL. Keep in mind the B2 and PRC-0234 do not obligated the TP to take this action, it only obligates Facility Owner to react if the TP identified a facility.

FAC-003 today does not exempt WECC utilities from having a sub 200kV line being identified as part of an IROL, and the revised language removes the term IROL, but inserts instead the definition of the IROL and the PC and TP Planning Assessment as a means of identifying those IROL-like facilities instead of the FAC-010 methodology.

FAC-003 R6 currently requires inspections once per calendar year, and allows to a limited extend (18 months) more than a year to pass between inspections. The measure is crafted using the same language so the SDT is unclear on the benefit of modifying the measure and not the requirement. Additionally this particular requirement and measurement pair is not directly within scope nor in the body of administrative corrections the team has incorporated into the standard.

FAC-014-3 R8 was put in place to insure that the PC and TP communicated information that TO and GO may need to conform to existing standard, addressing an existing current gap that did not require that communication. The addition was not intended to replace PRC-026 R1. PRC-026 R1 specifically refers to angular stability constraint, an angular instability or relay tripping due to power swings which is different list of criteria, though at times overlapping, than what is referenced in the proposed FAC-014-3 R8. PRC-026 then specifically references R1 as

the facilities that need to be considered for the steps identified in PRC-026. Replacing PRC-026 with R1 may result in some facilities not being identified, and the identification of facilities that wouldn't benefit from the PRC-026 requirements.	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	
Likes 0	
Dislikes 0	
Response	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

NO. NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments. Additionally, NERC has a SER project. Project 2015-09, Establish and Communicate, System Operating Limits, proposals create more redunancies; counter to the purpose of the SER project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the SDT drafting team's response to John Allen's comment. The SDT agrees that even with these changes there are still some redundancies within the standards, but believes that our work has improved reliability, clarity, efficiency and reduced some of the prior redundancies.	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	
Document Name	
Comment	
Xcel Energy recommends a longer implementation plan due to the coordination and potential tools required.	
Likes 0	
Dislikes 0	
Response	
The SDT has extended the implementation time to 24 months.	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	

Answer	
Document Name	CIP-014 SBS Comments 8-3-2020.docx
Comment	
Thank you for your comment. The SDT will not be making revisions to CIP-014 at this time.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits
Comment Period Start Date:	6/19/2020
Comment Period End Date:	8/26/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits CIP-014-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-003-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-011-4 AB 3 ST 2015-09 Establish and Communicate System Operating Limits FAC-013-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 3 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 3 OT 2015-09 Establish and Communicate System Operating Limits IRO-008-3 IN 1 ST 2015-09 Establish and Communicate System Operating Limits PRC-002-3 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-023-5 AB 2 ST 2015-09 Establish and Communicate System Operating Limits PRC-026-2 AB 2 ST 2015-09 Establish and Communicate System Operating Limits TOP-001-6 IN 1 ST

There were 76 sets of responses, including comments from approximately 173 different people from approximately 119 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

For this posting, responses to questions 4 and 5 regarding FAC-014 are provided. The remaining responses will be posted at final ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Industry response to the SDT's second posting, and specifically the new FAC-011-4, Requirement 6, indicated numerous and significant concerns. Among the concerns were many industry commenters stating that SOL exceedances should be determined using the TOP and IRO standards and not an FAC standard. The SDT has responded by revising FAC-011-4, Requirement 6, removing FAC-014-3, Requirement 6, and adding TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 to have SOL exceedances determined by TOPs and RCs, respectively, per the RC's SOL methodology and the performance framework now within FAC-011-4, Requirement R6. Do you agree with revisions made by the SDT in FAC-011-4, FAC-014-3, TOP-001-6 and IRO-008-3 with regard to SOL exceedance use and determinations?

2. Industry response to the SDT's second posting included many concerns regarding increased compliance and administrative logging from the SOL exceedance construct in FAC-011-4, Requirement 6. In response to these concerns, the SDT revised Requirement 6, added a new Requirement 7 to document a risk-based approach for determining how SOL exceedances are identified, and how they are communicated, including timeframes. The SDT also revised requirements and measures in TOP-001 (M14, R15, M15) and IRO-008 (R5, M5, R6, M6) to address this concern. Do you agree with revisions made by the SDT in FAC-011-4, TOP-001-6 and IRO-008-3 with regard to increased compliance risk and administrative logging?

3. If you have any other comments regarding FAC-011-4 that you haven't already provided, please provide them here.

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

6. If you have any other comments regarding TOP-001-6 or IRO-008-3 that you haven't already provided, please provide them here.

7. With the retirement of FAC-010, and the elimination of Planning-based SOLs and IROLs, do you agree with the changes to CIP-014, FAC-003, FAC-013, PRC-002, PRC-023 and PRC-026?

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
PPL - Louisville	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF

Gas and Electric Co.					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC

ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					John Hasting	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC

					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc	2	MRO
					Tim Miller	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					will Tootle	Southwest Power Pool Inc.	2	MRO

					Charles Cates	Southwest Power Pool Inc.	2	MRO
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

4. The SDT has received numerous comments on the new FAC-015-1 since the first posting. Acknowledging these comments, the SDT has withdrawn FAC-015-1 and consolidated its four requirements into three requirements (R6 – R8) in proposed FAC-014-3 that retain the minimum requirements the SDT believes will allow retirement of FAC-010 and maintain limit/criteria coordination between operations and planning. Do you agree with the proposed requirements R6 through R8 in FAC-014-3?

Marco Rios - Pacific Gas and Electric Company - 1

Answer	No
Document Name	

Comment

In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, “instability” must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The intent of R6 is to provide a mechanism for performance criteria (ratings, voltage/stability limits) to be coordinated between operations and planning in an effort to ensure there is appropriate agreement on these criteria. If there is confusion on the RC's methodology, there is nothing that precludes the PC or TP from seeking this clarity directly from the RC. The PC & TP are also afforded the flexibility to document a technical rationale to describe deviations between criteria used in planning from those prescribed in the RC's SOL methodology. R7 requires information communicated on corrective actions developed to address instability. As such, small generators pulling out of synchronism for P1 events is not applicable to R7.	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	
FAC-015 seems as an attempt to provide for the PC to TP heirarchy that should exist. However, it appears that there is a lack of coordination between FAC-011, FAC-014, and FAC-015. The goal should be to keep establishment of the Operating and Planning Horizon planning assessment with the closest entity (i.e. the Transmission Planner) and have the results go up the chain (subject to review and approval) from the TP to the PC to the RC and down to the TOP. The existing combination appears to include would that will not be used and is therefore wasting time and not accomplishing reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FAC-015 is not part of this posting. The SDT embedded the requirements into the current draft of FAC-014 posted in conjunction with this project.	
sean erickson - Western Area Power Administration - 1	
Answer	No

Document Name	
Comment	
WAPA agrees with removing the redundancy of the proposed FAC-015-1 and part of the shift of those requirements to the revised FAC-014-3. However, the proposed FAC-014-3 Requirement R6 remains redundant to existing obligations of MOD-032-1 and TPL-001-4 (soon -5) Requirement R1. The proposed Requirement R6 establishes a significant Compliance risk to planning entities who seek to plan the future transmission System for expansion and load growth, and ignores that Facility Ratings of the moment may not exist in the future planned System. In the proposed Requirement R7, it is unclear what reliability objective is accomplished that is not redundant to the existing IRO-017-1 Requirements R3 and R4. Furthermore, if there is a need to modify TPL-001-4 (soon -5) Requirement R8 to address annual Planning Assessment distribution, it should be revised there. Finally, to reiterate the comment above, FAC-014-3 Requirement R8 is not clear about requiring Planning Coordinators to communicate that "big-3" impacts during a particular planning event (e.g. see Cascading during simulation of a P6 event) were ***observed*** versus that "big-3" impacts ***caused*** a failure to meet System performance requirements. Here, the SDT is making a different interpretation than most planning entities make regarding TPL-001-4 (soon -5). It is not simply that "big-3" impacts were observed; it is that the "big-3" impact required a Corrective Action Plan (CAP) because the Contingency caused a failure to meet System performance requirements of Table 1. In other words, for a P6 event that yields Cascading, the Table 1 performance requirements may allow shedding Non-Consequential Load as part of the allowable mitigations such that System performance requirements are met (and no CAP). WAPA requests that the SDT reconsider the incorporation of the planning entity requirements into FAC-014-3 and, if retained, clearly state the intended reliability objective to retaining them there.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6	

of TPL-001-4, compared to that reflected in the RC's SOL Methodology. IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. R8 is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Wayne Guttormson - SaskPower – 1	
Answer	No
Document Name	
Comment	
Understand the good-faith intent of the SDT, but fundamentally the proposed requirements are TPL 001 based (and perhaps even FAC 008 based) and should be placed in the applicable standard if deemed acceptable. The draft standard appears to mandate the Facility Ratings, System steady-state voltage limits and stability criteria to be used by the PC/TP, as set by the RC/TOP methodology. It would probably be	

more effective to rewrite the drafted FAC-014 standard for the RC's/TOP's to provide their associated technical rationales (beyond a methodology) for the defined operating limits to the PC/TP for input into the TPL assessments. In general, having standards placing requirements for other standards (as a standards setting practice) risks creating confusion. Also support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Jamie Johnson - California ISO – 2	
Answer	No
Document Name	

Comment

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

CAISO believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. Keeping "like" requirements together in one standard will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid undue regulatory burden and support the efforts of the Standards Efficiency Review project. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn without adding Requirements R6 to R8 in FAC-014-3. Accordingly, we recommend:

- Requirements R6 to R8 be removed from FAC-014-3
- The phrase " and that Planning Assessment performance criteria is coordinated with these methodologies." be removed from the Purpose (Section 3) of FAC-014-3
- The Planning Coordinator and the Transmission Planner be removed from the Applicablity Section.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Applicable Facility Ratings Duration Criteria was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2), whose purpose is "To establish consistent modeling data requirements and reporting procedures [for each Transmission Owner, Transmission Service Provider, Generation owner, Resources Planner, and Balancing Authority]. TPL-001-4, R1 requires each Planning Coordinator and Transmission Planner to maintain models that use data consistent with that provided in accordance with the MOD-032 Standard that represent projected System conditions. TPL-001-5 further requires that Applicable Facility Ratings shall not be exceeded and that system adjustments are allowed to mitigate rating exceedances if such adjustments are executable within the time duration applicable to the Facility Ratings. If the SDT believes additional detail, such as a criteria regarding which of the

Facility Ratings (30 min, 4 hour, continuous, etc.) are applicable under normal and emergency conditions is required, we suggest TPL-001-4 be updated to include those details/criteria so that all related requirements are located together. TPL 001-5 also requires the Planning Coordinator and Transmission Planner to establish system steady state voltages, post-Contingency voltage deviation and transient voltage response. Instead of making the RC's SOL methodology, which is typically developed entirely from the operations perspective without involvement of the PC(s) and TPs, binding on PCs and TPs, TPL-001-5 can be modified so that the RC is a party in the development of the criteria, possibly through a process that is led by Regional Reliability Organizations such as WECC.

As we noted above, keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

In addition, reading the proposed Requirement 6.2 of FAC-011-4, it doesn't appear that there is a material risk for the PC and TP to use less restrictive criteria than the RC that makes including Requirement R6 in FAC-014-3 necessary.[1]

[1] The system performance standards FAC-011-4 requires the RC to include in its SOL methodology are:

Ø System performance for no contingencies demonstrates flows and voltages are within normal ratings but emergency limits may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

Ø System performance for single contingencies demonstrates flow through facilities and voltages are within applicable Emergency Ratings and System Voltgae Limits. Steady steate post-Contingency flow through a facility must not be above the Facilitiy's highest Emergency Rating.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to either: (1) actually include the desired criteria, including the Applicable Facility Ratings Duration Criteria, in FAC-014-3 possibly using similar language as used in Requirement R6 of FAC-011-4 while maintaining consistency with the requirements in TPL-001-5 mentioned above, rather than leaving it to the RC's SOL methodology, or (2) to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings criteria, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage

Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

If on the other hand it can be assumed that the SDT is referring to Applicable Facility Ratings Duration Criteria rather than individual Facility Ratings, System voltage limits rather than Facility specific voltage limits and system stability limits then the provision of technical rationale be limited to the Regional Reliability Organization (RRO) as part of the established compliance monitoring process rather than to multiple entities to avoid putting additional regulatory burden on PCs and TPs.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 or Requirement R8 of TPL-001-5 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion, avoid undue regulatory burden, and support the efforts of the Standards Efficiency Review project.

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R3 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 or TPL-001-5, R8 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion, avoid placing undue regulatory burden on entities and support the efforts of the Standards Efficiency Review project. We strongly oppose the requirement to inform multiple entities including generator owners because, that could take planning engineers away from their core job. The existing FAC-014 limits such communication to the affected RC. We recommend that arrangement remain unchanged.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all.

R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

With respect to Requirement R6, ERCOT believes the language contained in the prior draft of FAC-015 should be utilized. The current draft of FAC-014 seems to suggest that responsible entities must provide a technical rationale to each Transmission Planner, Transmission Operator, and Reliability Coordinator in the event of the utilization of a higher rating than was provided for an upgraded circuit. Accordingly, ERCOT suggests replacing the proposed language of Requirement R6 with the language previously utilized in Requirements R1, R2, and R3 of FAC-015.

With respect to Requirement R8, ERCOT believes the Planning Coordinator (PC) and Transmission Planner should communicate only the limited information each Transmission Owner and Generator Owner (GO) needs to know, not necessarily the full details regarding the nature of the instability, Cascading, or uncontrolled separation. ERCOT suggest the use of the following language in Requirement R8:

Each Planning Coordinator and each Transmission Planner shall provide an annual communication to Transmission Owners and Generation Owners that own Facilities that meet the following conditions: 1. The Facility is part of a planning event contingency that the Planning Coordinator or Transmission Planner has identified in its annual Planning Assessment would cause instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the BES if a limit is exceeded; or 2. The Facility is part of a contingency associated with an established IROL or stability limit, which was provided to the Planning Coordinator or Transmission Planner under Requirement R5, Part 5.2.4. ERCOT also suggests modifying the standards that utilize such information, which are part of this ballot/comment period, to include "Facilities identified in FAC-014" or "FAC-014-3, Requirement R8" as appropriate so that the facilities that must meet those requirements include part 2 suggested above. ERCOT further notes that it intends to vote in favor of FAC-014-3, provided the foregoing suggested modifications are incorporated.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Requirement R6 in the current draft of FAC-014 is a simplification of the R1 – R3 language in the previous posting of FAC-015. The SDT believes the intent of the previous FAC-015 requirements is preserved in R6 of FAC-014. The SDT took your comment regarding FAC-014-3, R8 under consideration and modified the language accordingly. This change will be reflected in our next posting of FAC-014-3.

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the Facility Ratings, System steady-state Voltage Limits and stability criteria as determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

- The Planning Coordinator may use less limiting Facility Ratings as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator

Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data.

FAC-014-3, R7

We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

FAC-014-3, R8

We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all.

R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The IRC SRC believes the three requirements (R6-R8) proposed for FAC-014-3 are all misplaced and are duplicative of other existing NERC requirements in the following NERC standards: IRO-017, MOD-032 and TPL-001 as described below. For these reasons, we believe that FAC-010 can still be retired even if FAC-015 is withdrawn.

FAC-014-3

We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Factility Ratings? This set of standards talks about Steady State Voltage Limits, Stability Limits, but is silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Rating.

FAC-014-3, R6

We believe FAC-014-3, R6, i.e. to implement a documented process for Facility Ratings, voltage limits and stability criteria, is duplicative of existing NERC Standard MOD-032-1 (R2) and TPL-001-4, R1 which require each Planning Coordinator and Transmission Planner to maintain models that represent projected System conditions. If the SDT believes additional detail is required, we suggest MOD-032 or TPL-001-4 be updated so that all related requirements are located together. Keeping "like" requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project

If FAC-014-3, requirement R6 is not retired, the IRC SRC requests that it be modified to acknowledge that the determination of Facility Ratings is the responsibility of Generator Owners (GO) and Transmission Owners (TO) under FAC-008-3 as follows:

Proposed Language:

FAC-014-3, R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that represent projected System Operating Limits that are equally limiting or more limiting than the ***(delete - criteria for)*** Facility Ratings, System ***steady-state*** Voltage Limits and stability ***criteria*** as ***determined by the Transmission Owners and Generator Owners in accordance with FAC-008 and provided to the PC via MOD-032, R2 and in accordance with their respective RC's SOL methodology (FAC-011-4, R9).***

Likewise, the requirement for the PC to notify impacted entities and provide a technical rationale for the use of a less limiting Facility Rating in its Planning Assessment (under FAC-014-3, R6) is misplaced. Instead, the IRC SRC recommends FAC-008-3 be revised (*see* requirement R8) and expanded to require GOs and TOs notify applicable entities, including the PC, of planned upgrades that will increase a Facility Rating and modify FAC-014-3 to recognize this.

· The Planning Coordinator may use less limiting Facility Ratings ***as provided by the GO or TO (in accordance with FAC-008-3, R8), to recognize planned upgrades in the Near Term Transmisison Planning Horizon***, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator Alternatively, MOD-032, R3 could be updated to reflect this detail as MOD-032-1, R3, Part 3.1 already requires Balancing Authorities, Generator Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers to provide an explanation with a technical basis for the data. **FAC-014-3, R7** We believe FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase effiiciency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project. **FAC-014-3, R8** We believe FAC-014-3, R8 is duplicative of existing NERC Standard TPL-001-4, requirements R6 and R8 and IRO-017-1, R4 which collectively include the obligation for the Planning Coordinator and Transmission Planner to define and document when the Planning Assessment indicates the inability of the system to meet the performance requirements, including System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding and to provide its Planning Assessment to impacted Reliability Coordinators. In addition, TPL-001-4, R8 allows any functional entity that has a reliability related need need to request this information. If the SDT believes additional detail is required, we suggest that IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. Keeping “like” requirements together will retain the overall context of the requirements, increase efficiency, minimize opportunities for confusion and support the efforts of the Standards Efficiency Review project.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014, as well as FAC-011-4. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology. IRO-017-1 deals with outage coordination, not SOLs, and as such, the SDT believes FAC-014 remains the proper place for SOL transmittal and related information between entities. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirements in TPL-001-4 and IRO-017-1 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Lee Maurer - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

FAC-014-3 R6

The SPP Standards Review Group asks the SDTs consideration that coverage of FAC-014-3 is included in the data provided in MOD-032-1, and in the model building in TPL-001-4 R1, where the models contain Facility Ratings, System steady-state voltage limits, and stability criteria that are equally limiting or more limiting than the ones utilized by the Reliability Coordinator (RC).

The SPP Standards Review Group asks the SDTs consideration of these differences in the scope for TPL-001-4 R1.

The development of Facility Ratings is the responsibility of the Transmission Owner (TO) in accordance with FAC-008-3. To allow the Planning Coordinator (PC) or Transmission Planner (TP) to develop a “less limiting”, “higher” Facility Rating, could lead to unrealistic and/or invalid Planning Assessments.

The PC and/or the TP should not have the ability to overrule the TOs capability to maintain conservative Facility Ratings in accordance with manufacturer recommendations to protect its personnel and equipment. If the PCs and TPs want to adjust system models with a higher Facility Rating based on a proposed system upgrade, that is included in TPL-001-4 R1, Part 1.1.3. FAC-014-3 R6, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures. **FAC-014-3 R7** The SPP Standards Review Group asks the SDTs consideration that TPL-001-4 R8 is for the PC and TP to share information on their annual Planning Assessments. The SPP Standards Review Group recommends that the list of entities in TPL-001-4 R8 include RCs and TOPs the ability to request and receive the information. FAC-014-3 R7, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures. **FAC-014-3 R8** The SPP Standards Review Group considers existing coverage of FAC-014-3 R8 in TPL-001-4 R8. The SPP Standards Review Group recommends that the list of entities in FAC-014-3 R8 include TOs and Generator Owners (GOs) the ability to request and receive the information. FAC-014-3 R8, as written, could lead to the misunderstanding of the context, the expectations, and/or the compliance failures.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Additionally, there is no ability for the PC or TP to overrule the owner in the development of Facility Ratings. The owner, per FAC-008, develops and communicates its Facility Ratings and any relevant assumptions for these ratings. The operators and planners are then required to use these ratings, or the appropriate subset of them in the planning and operating studies of the system. The intent of R6 in the current proposal is to ensure planners are not using less limiting ratings than the RC has allowed for in operations (example: The PC & TP should not plan to a 30-minute rating if the RC only allows for operators to operate to a 2-hour rating). R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The proposed requirements R7 and R8 in FAC-014-3 are unnecessary. Requirement R5 ensures that the Reliability Coordinators provide the Plannning Coordinators and Transmission Planners the SOLs for their respective areas. If instability is identified in the Planning Assessments which drives an SOL, it would be provided to the TOPs through instabilitie identified by requirement R5. If the identified instability does not	

require an SOL then providing that information to TOPs could lead to uncertantity as to what to do with the information. Many of the instabilities identified by Planning should be items strictly for the Planning Horizon, as Planning should be addressing them with Corrective Action Plans prior to them making it to become a Real Time Operating Horizon SOL issue. FAC-014 Requirement R6 is more appropriately placed in the TPL-001 standard to avoid possible confusion in completing the task in finalizing the completion of the models needed for performing the Near Term Assessments. All of the other requirements for the models are identified in this standard.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Requirement R5 of the current draft for FAC-014 is RC information being communicated to other entities. R7 & R8 involve information identified by the planners being communicated to the appropriate entities. This represents different communication paths involving different sets of data/information. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. R6 merely requires consideration of the criteria used in planning, which could include the thermal ratings modeled in the cases created per MOD-032-1 or TPL-001-4, R1, or the criteria (voltage and stability) the planner documented per R5 and R6 of TPL-001-4, compared to that reflected in the RC's SOL Methodology.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	
While EEI is supportive of the general concepts for Requirements R6 through R8, the language lacks sufficient clarity to address what results or outcomes are expected. Given this ambiguity, the outcomes could result in inconsistent application across the various regions. Moreover, the current language in these three requirements do not adequately conform to the tenant of a Results Based Standard. For these reasons, we cannot support the currently proposed draft of FAC-014-3 at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The ambiguity referenced and the risks it presents is not particularly clear so the SDT cannot respond further or determine an action plan to address.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 "Establish and Communicate System Operating Limits" should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.	

Southern Company also suggests a modification to R7 of the proposed FAC-014-3 that will help focus the communication of any instabilities identified in the Planning Assessment to include only those contingency events which are the most impactful, as follows:

R7 Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the near-Term Transmission Planning Horiozon, ***using planning event contingencies only****, to each impacted Reliability Coordinator.*

FAC – 014 R7 and R8 could result in burdensome communication even if there isn't any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

Modify the last sentence of FAC-014 R7 from "This communication shall include:" to "This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:"

Modify the first sentence of FAC-014 R8 from "shall annually communicate any instability…" to "shall annually communicate if there is any identified instability……."

Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

Clarifying wording changes to R7 & R8 were considered, and changes were made to R7 to have the PCs and TPs identify only the facilities to the transmission and generation asset owners. The SDT considered your suggested revisions to R7 and R8, but considered the value of an annual affirmation of "no instability impacts" more clear and precise than the suggested revision implying "no instability impacts" exist if no communication occurs.	
Michael Jones - National Grid USA – 1	
Answer	No
Document Name	
Comment	
FAC-014-3 Requirements (R6– R8) are not well aligned for inclusion in a FAC Standard and there are already similar requirements in TPL-001-4. Requirement R8 in FAC-014-3, which requires annual communication of any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment, appears to already be covered by requirement R8 in TPL-001-4. In addition, FAC-014-3 Requirements (R6 - R8) are only related to the Near-Term Transmission Planning Time Horizon. There appears to be a need for further clarification regarding the relevant Time Horizon(s) which reference: "Time Horizon: Long-term Planning."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	

The Near-Term Transmission Planning Horizon was chosen since the beginning of this time horizon is where you have overlap with the operating horizon. Additionally, a focus on near-term information from planners to be communicated to operators is typically more relevant and certain and is therefore of more use to operators.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Daniel Gacek - Exelon – 1	
Answer	No
Document Name	
Comment	
On behalf of Exelon, Segments 1, 3, 5, & 6 Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	No
Document Name	
Comment	

NV Energy does not agree with the proposed requirement R6 of FAC-014-3. The proposed requirement requires additional clarity on the potential opportunity of a RC creating a Facility Rating based upon its own SOL methodology, and removing the ownership provided to Entities through FAC-008-3. FAC-014-3 requirement R6, currently reads that each Planning Coordinator and Transmission Planner shall implement a process to use Facility Ratings…that are equally limiting or more limiting than the criteria for Facility Ratings…as described in its RC's SOL methodology. NV Energy currently interprets this this as the RC can create a Facility Rating based on its own SOL methodology. Under this interpretation of the requirement, NV Energy cannot approve the current draft of the requirement R6..

Additionally, the remainder of the Standard, FAC-014-3, states that the PC and TP may use less limiting Facility Ratings, if the Entity provides a technical rationale. NV Energy interprets the intention of this language that the TP can use a less limiting element (higher facility rating) than what the RC provides, but that isn't entirely clear in the requirement's current draft.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The RC is bound to use the owner-provided Facility Ratings. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 1, 5, 3, 6; Bryan Taggart, Westar Energy, 1, 5, 3, 6; Derek Brown, Westar Energy, 1, 5, 3, 6; Grant Wilkerson, Westar Energy, 1, 5, 3, 6; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., ; James McBee, Westar Energy, 1, 5, 3, 6; Marcus Moor, Westar Energy, 1, 5, 3, 6; - Douglas Webb, Group Name Westar-KCPL

Answer	No

Document Name	
Comment	

The Evergy companies support, and incorporate by reference, Edison Electric Institute's response to Question No. 4.

Evergy would further respond:

Proposed Revisions Add Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to use "less limiting" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No

Document Name	
Comment	
The proposed Requirements R6-R8 in FAC-014-3 all require actions associated with the PC and TP annual Planning Assessment, which is required by TPL-001. If not already sufficiently addressed by the Requirements in TPL-001, we believe it would be better to address any additional actions associated with the annual Planning Assessment in a revision to TPL-001 to avoid requirement fragmentation between TPL-001 and FAC-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The proposed FAC-014-3 Requirements R6 through R8 obligate the Planning Coordinator and Transmission Planner to share information on their annual Transmission Planning Assessments. The proposed requirements are redundant because Planning Coordinators and Transmission Planners are already required to share planning assessments under TPL-001-4, Requirement R8. Requirement R8 states: “**Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability**	

related need and submits a written request for the information within 30 days of such a request." The proposed requirements would be inefficient, increase administrative compliance responsibilities, and would be contrary to ongoing work of the NERC Standards Efficiency Review project. Alternatively, if the SDT does not withdraw Requirements R6 through R8, the intent with regard to the Time Horizon must be clarified. SOLs applied to support the Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. Stability limits identified by the Reliability Coordinator may become invalid in the Planning Time Horizon as new generation is potentially added in future power flow models. When this occurs, it is the Transmission Planner's and Planning Coordinator's stability limits that must be communicated to the Reliability Coordinator so that the Reliability Coordinator knows what to expect. Also, the two bulleted items in the newly proposed Requirement R6 are troubling. The development of Facility Ratings is the responsibility of the Transmission Owner, per FAC-008. To allow the Planning Coordinator and Transmission Planner to develop a "less limiting" Facility Rating could result in inaccurate Operational and Transmission Planning Assessments. The Planning Coordinator or Transmission Planner should not be allowed to independently overrule the Transmission Owner's responsibility to develop Facility Ratings.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.	

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	No
Document Name	
Comment	

BPA agrees with the withdrawal of FAC-015-1 and consolidating the requirements into FAC-014-3. However, BPA offers the following comments on the new Requirements.

FAC-014-3 Requirement R6: Facility Ratings are modeling data, as developed and reported in Standards FAC-008 and MOD-032. System steady-state voltage limits and stability criteria used in Planning Assessments are criteria developed and documented in annual system assessments required by Standard TPL-001.

BPA suggests including the following language (bold. italic text added) to add clarity to R6:

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that, when developing its steady-state modeling data requirements, Facility Ratings used in its Planning Assessment*** of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for Facility Ratings described in its respective Reliability Coordinator's SOL methodology. ***In addition, each Planning***

Coordinator and each Transmission Planner shall ensure that criteria developed and documented for System steady state voltage limits and stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3 Requirement 7: BPA believes it should only be necessary to communicate information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. This is also consistent with the SDT's response to comments from the previous posting.

BPA suggests including the following language (bold, italic text added) to add clarity to R7.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The above comment for R6 does capture the SDT's intent. The SDT will review the rationale for this requirement to ensure this clarity is captured.

The SDT is considering modifications, to the effect of the above comment, to R8 of the current draft of FAC-014.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	

Dislikes 0	
Response	
See response to referenced comment.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OGE supports the concerns expressed by MRO-NSRF on the proposed FAC-014 R6, R7 and R8. OGE believes that the proposed R6, R7 and R8 are duplicative of requirements in TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

While the intent of the requirements in FAC-014 does not appear to be reflected in the actual words. These requirements are confusing and create ambiguity that could result in incomsistent results, especially with auditors.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The ambiguity referenced and the risks it presents is not particularly clear so the SDT cannot respond further or determine an action plan to address.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. – 3	
Answer	No
Document Name	
Comment	
MEC Supports NSRF Comments	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. – 1	
Answer	No
Document Name	
Comment	

MEC supports MRO NSRF comments.

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions.*"

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation.

Clarification. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency.

R6 R7 R8 Shared Concerns

Compliance Ambiguity. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings. The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends that FAC-014-3 R7 be modified to include the phrase "during the planning events" as an added measure of clarity. For example: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified "during the planning events" in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. Additionally, due to the numerous methodologies, procedures, processes, tools, and training impacts associated with this Project, suggest extending implementation period from 12 months to 30 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The reference to CAPs in R7 and the associated rationale provide the clarity suggested in this comment in the SDT's opinion.	

The request for a reconsideration of the implementation period is duly noted and will be re-evaluated by the SDT.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP disagrees with incorporating R6-R8 into FAC-014 as currently proposed. It is not clear exactly what the SDT believes the benefits would be of such an approach. FAC-014 and its obligations have historically been centric to the Operations Planning Time Horizon, not the Near/Long Term Planning Horizon as currently proposed in these most recent revisions. To do so would change the original intent and purpose of FAC-014 into something more reminiscent of TPL-001. We believe the SDT needs to clarify their strategies and intentions regarding the “mixing” of these time horizons, and for them to further consider the unintentional impacts of making such changes. The “planning assessments” proposed in FAC-014 seem redundant to that which is already required under TPL-001. We believe the SDT needs to be clear as to the intent of R6-R8 with regard to the Time Horizon. SOLs applied to support Operations Planning Time Horizon will be different than those applied to the Long-Term Planning Time Horizon. If the intent is to ensure SOLs applied in the Operations Planning Time Horizon are incorporated in any Planning Assessments performed, the existing language does not accomplish this. An RC’s stability limits may become obsolete and thus inapplicable in the planning time horizon as new generation is added. When this happens, it is rather the TP’s and PC’s stability limits that ought to be communicated to the RC so the RC knows what to expect in the future. If industry and the SDT believe that the obligations proposed in R6-R8 are indeed worth pursuing, it may be worth considering including them within a new FAC standard of their own. The revised FAC-014 R6, R7, and R8 apply directly to the conduct and communication of planning assessments. While we recognize that TPL-001 is not within scope of the project’s SAR, we believe such obligations are already captured as part of TPL-001. FAC-014 R6 states “Each Planning Coordinator and each Transmission Planner shall implement a documented process”, but it is not clear exactly where the creation of this documented process is/was originally required.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The currently approved version of FAC-014 contains requirements of planners to establish and communicate SOLs per the PC SOL methodology. Therefore, the concept of the planning horizon is already fully embedded in FAC-014. The retirement of FAC-010, as proposed by the SDT, makes it necessary to replace the current SOL-based requirements with more appropriate mechanisms to ensure communication and coordination between planners and operators is provided for in the standard.

The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The data provided through TPL-001-4 only provides information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

R6 Concerns

The NSRF does not support incorporating R6 into FAC-014 for the following reasons:

Duplicative. Proposed R6 is covered by the data required under MOD-032-1 and TPL-001-4 R1 model building which specifies that models "*shall represent projected System conditions.*"

Questions for SDT Consideration

1. Wouldn't the models already evaluate System conditions against Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the RC?

2. Today, if there are differences, they should fall within the TPL-001-4 R1 audit scope.

Adds Reliability Risk. Transmission Owners are required to develop Facility Ratings under FAC-008. The proposed two bulleted subparts permit the Planning Coordinator or Transmission Planner to develop "*less limiting*" (higher) Facility Ratings. Inconsistencies between FAC-008 Facility Ratings and ratings developed under the R6 bulleted subparts can lead to unrealistic Planning Assessments or invalidate Planning Assessments, altogether.

The proposed bulleted subparts seek to address the described reliability risk by requiring PCs or TPs to submit a technical rationale to affected TPs, TOs, and RCs. The proposed revision to FAC-014-3 does not consider the possibility TPs, TOs, RCs not wanting to accept a risk posed by the technical rationale. As such, the PCs or TPs could effectively reject TP, TO, or RC concerns raised by the technical rationale and proceed to operate at the less limiting Facility Ratings, regardless of those concerns; for example, the Transmission Owner needing to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment.

We would note, however, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, there is a path to do so under TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7 Concerns

The NSRF does not support incorporating R7 into FAC-014 for the following reasons:

Duplicative. The information sharing under proposed R7 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment.

Recommendation. Revise TPL-001-4 R8 to permit Reliability Coordinators and Transmission Operators to request and receive the CAPs information as reflected in proposed FAC-014 R7.

R8 Concerns

The NSRF does not support incorporating R8 into FAC-014 for the following reasons: *Duplicative*. The information sharing under proposed R8 is already addressed under TPL-001-4 R8, which establishes the Planning Coordinator and Transmission Planner are required to share information as part of their annual Planning Assessment. *Recommendation*. Revise TPL-001-4 R8 to permit Transmission Owners and Generator Owners to request and receive the information in proposed FAC-014 R8, e.g. instability info, cascading and uncontrolled separation. *Clarification*. It looks as if the rationale document for FAC-014 infers the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners since they do not operate the system. If that is the intent, it would be helpful to clarify and unambiguously state that for purposes of transparency. **R6 R7 R8 Shared Concerns** *Compliance Ambiguity*. As stated, above, incorporating R6, R7, and R8 into FAC-014 creates inconsistencies within the context of the Standard, providing unclear performance expectations and ambiguity around potential noncompliance. As such, the proposed revisions are incompatible with the Standards Efficiency Review project's effort to reduce ambiguity around compliance.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard. There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade. The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	No
Document Name	
Comment	

R6. This requirement is out of place in FAC-014 and should already be covered in the data provided via MOD-032-1 and model building effort via TPL-001-4 R1, which specifies that models "*shall represent projected System conditions*". Therefore, why wouldn't the models already contain Facility Ratings, System steady-state voltage limits and stability criteria that are equally limiting or more limiting than those used by the Reliability Coordinator? If there are significant differences between how the system is being planned and how it's being operated, then that should be within the scope for auditing TPL-001-4 R1 today. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project.

Additionally, the two bulleted items are problematic since the development of Facility Ratings is the responsibility of the Transmission Owner in accordance with FAC-008. To allow the Planning Coordinator or Transmission Planner to develop a "*less limiting*" (higher) Facility Rating could lead to unrealistic and/or invalid Planning Assessments. The Planning Coordinator and/or Transmission Planner should not be allowed on their own to overrule the Transmission Owner's ability to maintain conservative Facility Ratings in accordance with manufacture recommendations to protect its personnel and equipment. However, if the Planning Coordinators and Transmission Planners want to adjust system models with a higher Facility Rating based on a proposed system upgrade, then that is already allowed via TPL-001-4 R1, Part 1.1.3. (*New planned Facilities and changes to existing Facilities*).

R7. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. Therefore, the list of entities in TPL-001-4 R8 should be enhanced to allow Reliabilty Coordinators and Transmission Operators the ability to request and receive this information.

R8. This requirement is out of place in FAC-014 and should be covered in TPL-001-4 R8 where the requirement for the Planning Coordinator and Transmission Planner to share information on their annual Planning Assessment resides. Having this requirement detached in FAC-014 could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project. It also appears in the rationale document for FAC-014 the sole purpose of this requirement is to facilitate compliance administration needs for the Transmission Owners and Generator Owners. Therefore, the list of entities in TPL-001-4 R8 should be expanded to allow Transmission Owners and Generator Owners the ability to request and receive this information.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

There is no provision in the current proposal of FAC-014 or any related standard proposal that allows a planner or operator to overrule an owner on its Facility Ratings.

The technical rationale provision is intended to allow the planner to use less limiting Facility Ratings (not a less limiting Element on a Facility) if they document the rationale why this is used. The most common instances for a planner to use less limiting Facility Ratings is when a Rating changes due to a future planned upgrade.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
In concept, the proposed requirements for FAC-014-3 R6 to R8 are good, but the details need to be further developed. For instance, for R6, the RC can change their methodology at any time and the Transmission Planner will then be responsible to ensure that any more stringent criteria are then reflected in Planning studies, but the RC is required by FAC-011-4 R9 to provide its SOL methodology to PCs and TPs, so there	

should be adequate notification which would allow the TP to implement such changes in their next reliability assessment. The greatest concern, then, appears to be possible disconnects between Operating and Planning criteria that make it difficult to ensure compliance with R6 and leave certain aspects up to interpretation, such as differences in Facility Ratings used in Operations vs. Planning. The standard as currently written does not require the RC to accept and respond to feedback from other entities if the methodology is unclear, but R6 will require the PC and TP to correctly interpret the methodology for ratings, limits, and criteria. For R7 and R8, the concept of notification to TOPs/RCs (R7) and TOs/GOs (R8) is sound, but the implementation may not be straightforward. In R7, for instance, "instability" must be communicated – does this include small generators that lose synchronism for P1 events? How does an entity differentiate bad models from instability when compliance directly depends on notifications of such issues? Clear definitions of the terms involved here would be a significant improvement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent of R6 is to provide a mechanism for performance criteria (ratings, voltage/stability limits) to be coordinated between operations and planning in an effort to ensure there is appropriate agreement on these criteria. If there is confusion on the RC's methodology, there is nothing that precludes the PC or TP from seeking this clarity directly from the RC. The PC & TP are also afforded the flexibility to document a technical rationale to describe deviations between criteria used in planning from those prescribed in the RC's SOL methodology. R7 requires information communicated on corrective actions developed to address instability. As such, small generators pulling out of synchronism for P1 events is not applicable to R7.	
Maurice Paulk - Cleco Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See SEE, EEI and MISO comments	

Likes 0	
Dislikes 0	
Response	
See response to referenced comment.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
IPL offers no further comment.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Thank you.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
In our opinion we need to be careful that there is only one methodology for SOL's going forward. We agree with the proposed requirements but also suggests that the team consider instead adding these requirements within TPL-001, which deals with the Planning Assessment and correspondence/communication of the Planning Study to affected entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We have an overall concern with the term Facility Rating as applied in these FAC Standards and the confusion with those used in the MOD Standards. Does the SDT really mean Thermal Operation Limits as developed from the Facility Ratings? This set of standards talks about	

Steady State Voltage Limits, Stability Limits, but us silent on Thermal Operation Limits. We believe it would provide more clarity if the term Thermal Operation Limit was used in place of Facility Limit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Facility Ratings, as referenced in the current draft of FAC-014, is consistent with the NERC glossary term as it is in all NERC Reliability Standards. Per the definition, the maximum current, real or reactive power flow should constitute the thermal limits for facilities, which is part of the Facility Rating. Further, the SDT recognizes the owner's responsibility in determining Facility Ratings per FAC-008 and this is supported in the current proposal for FAC-014. Thermal Operation Limits is not defined in the NERC Glossary and is therefore not an appropriate reference for a NERC Reliability Standard as different entities may or may not use this terminology the same way if they use it at all.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
FAC-014-3 The statement "any instability identified in its Planning Assessment of the Near-Term Transmission…" seems unclear. I think an improvement and more clear statement might be, "any stability criteria violation identified in its Planning Assessment of the Near-Term Transmission…".	

The revision that Oncor is proposing also seems to better align with the deliverables outlined in R7.1 – R7.5, and in particular, R7.3: The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Clarifying modifications to R7 and the associated rationale are being considered by the SDT.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
1. The IESO is concerned that there is no requirement for the affected RC to provide feedback on the technical rationale provided by the PC or TP for using less limiting ratings. The IESO proposes to add a sub-requirement to establish this feedback loop between the affected entities and the PC or TP. The proposed requirement would mirror Requirement R8, sub-requirement 8.1. of Reliability Standard TPL-001-4 which allows the recipient of the Planning Assessment results to provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments: ***Proposed Requirement R6, Sub-requirement 6.1:*** ***"The recipient of the technical rationale may provide documented comments on the results, and the respective PC or TP to provide a documented response to that recipient within 90 calendar days of receipt of those comments"***	

Alternatively, the IESO would like to clarify if Requirement R8., subrequirement 8.1 is the feedback loop that can be used to address the lack of input from the affected entities on the technical rationale provided by the PC or TP on the use of less limiting ratings (this is based on the assumption that the technical rationale would be part of the Planning Assessment results).

2. Similar with the Reliability Standard TPL-001-4 where an RC can provide input on the Planning Assessment criteria, the IESO believes that the PC and TP should be afforded the reciprocal opportunity to provide input to its RC's methodology and have the RC provide a document response.

The IESO proposes to add *Sub-requirement R9.3 to FAC-011-4 as follows:*

"9.3. If a recipient of the Reliability Coordinator SOL methodology provides documented comments on the methodology, the respective Reliability Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments."

3. We find that Requirements R7 and R8 are duplicative of existing communication requirements within other Reliability Standards. Specifically,

{C}o **Requirement R7 requires the PC and TP to communicate, annually any CAP identified in its Planning Assessments to the RC. Requirement 8 in TPL-001-4 requires the PC and TP to provide its Planning Asssessment results to affected entities, which include any CAP developed in R2 Sub-requirements 2.7 of TPL-001-4; and**

{C}o **Similarly, Requirement R8 requires the PC and TP to communicate, annually , any instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES in its Planning Assessment of the Near-Term Transmission Planning Horizon to TOs and GOs. All Planning Assessments performed by PCs and TPs are governed by other standards (TPL-001, PRC-012, PRC-023 etc.) and the processes required by those standards already include provisions for the communication of those results to the entities that have a reliability need.**

We suggest that Requirements R7 and R8 be removed to avoid duplication with existing communication obligations for the PC and TP.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The SDT understands the perception of redundancy of the proposed R6 & R7 with other requirements in existing Reliability Standards (TPL-001, MOD-032, etc.). Consideration was given to modifying other standards to accomplish the scope of the 2015-09 project SAR but industry and regulatory comments/input on those proposals moved the SDT down the current path of incorporating the concepts contained in these requirements into the FAC-014 standard. Additionally, the concept of coordinating and communicating information between planning and operations for the purpose of establishing and communicating SOLs is also appropriately placed in the FAC-014 Reliability Standard.

The feedback loop for the RC to the PC and TP concern is noted. This was not included in the current draft language due to a potential perception of "approval" of the rationale by the RC, which could imply an authority by the RC over the planners. This authority is not supported in the NERC functional model and a requirement for the planners to document a response only seemed administrative in nature and was thus not included.

The SDT discussed at length the annual planning assessment created per TPL-001, and noted that the specific information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability.

In addition, FAC-014-3, R8, is intended to comply with the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. The cited requirement in TPL-001-4 (R8) only provided information to the operating entities (RCs and TOPs), and not the asset owners, as requested in FERC order 777.

Ray Jasicki - Xcel Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; Glen Allegranza, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Truong Le - Truong Le On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 5, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 5, 3; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Truong Le	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Michael Courchesne - Michael Courchesne On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Michael Courchesne	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mickey Bellard - Seminole Electric Cooperative, Inc. - 1,5 - SERC	
Answer	
Document Name	FAC-014 SBS Comments 8-3-2020.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

5. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	

R3. What is the purpose of the Transmission Operator providing its SOLs to the Reliability Coordinator? If it's for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then keeping this requirement is redundant with the data specification in IRO-010-2 and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Reliability Coordinator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Furthermore, by definition SOLs change continuously based on "*a specified system configuration*". Therefore, does the SDT expect the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment? This is another reason why the information/data exchange activity needs to remain within IRO-010-2, where each Reliability Coordinator can determine the items that need reported, the method and a timeframe based on their individual operating environment.

R5.1 and R5.2. If one purpose of Project 2015-09 is to eliminate planning-based SOLs and IROLs, then what is the purpose of the Reliability Coordinator providing them to the Planning Coordinator and Transmission Planners in this requirement? If it's for the purpose of better aligning planning and operations, then where is the requirement for the Planning Coordinator or Transmission Planner to use them in the models for the Planning Assessments? If there isn't a corresponding obligation, then it potentially becomes an administrative compliance exercise that isn't benefiting reliability. Additionally, the model building topic is covered in MOD-032-1 and if the intent is to use additional information identified during operations in the models for TPL-001-4 Planning Assessments, then MOD-032-1 should be enhanced and the

Reliability Coordinator should be added to the applicability. Having it dispersed in other standards could lead to misunderstanding of context, expectations and/or compliance failures, which is not effective or efficient.

R5.3 and R5.4. What is the purpose of the Reliability Coordinator providing IROL information to the Transmission Operators? If it's for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments, then the data specification concept should be maintained and TOP-003-3 should be enhanced to allow the Transmission Operator to request and receive information from its Reliability Coordinator. To keep these requirements detached in FAC-014 is not effective or efficient and contrary to ongoing work by the Standards Efficiency Review project to simplify data exchange requirements, reduce administrative burdens and remove redundancies. If not used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and/or Real-time Assessments, then please explain the purpose and the corresponding obligation by the Transmission Operator to use the information? Otherwise, it potentially becomes an administrative compliance exercise that distracts our operations personnel and isn't benefiting reliability.

Likes 0	
Dislikes 0	

Response

R3: This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010 and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. This requirement does not preclude the RC from having the flexibility of specifying the SOL information it requires from the TOP to satisfy the requirement within its SOL Methodology such that there's a clear expectation of what's to be provided.

R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may influence them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information which is key to maintaining reliable operation across our interconnections.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
NCPA supports John Allen's, City Utilities of Springfield, Missouri, comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. R3: This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010 and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. This requirement does not preclude the RC from having the flexibility of specifying the SOL information it requires from the TOP to satisfy the requirement within its SOL Methodology such that there's a clear expectation of what's to be provided. R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement. R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information which is key to maintaining reliable operation across our interconnections.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

It is also important that RC and/or TO provide technical rationale to PC if they are

using less restrictive SOLs than PC's SOLs.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The proposed standard requirement R6 suggests the PC and TP use more restrictive limitations, ratings, and performance criterion. Since this is in line with the proposed requirement, the SDT doesn't see why a rationale would be needed. If opposite were the case, i.e. where RC and TO are proposing to more restrictive criterion than PCs and TPs are using, the PC and TP need to flag this and work with the RC and TOP to build the technical rationale as the requirement is on the PC and TP to ensure.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

"These comments represent the MRO NSRF membership as a whole but would not preclude members from submitting individual comments".

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement. R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement. R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP – 5	
Answer	
Document Name	
Comment	
If retained, we believe FAC-014 should be revised as "Each Reliability Coordinator shall establish stability limits to be used in operations when *an instability* impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Your suggestion was used to revise the language in the requirement.	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	
Document Name	
Comment	

R5.5: This language is awkward. Please clarify and reword to capture intent.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. This is a statement that highlights that the RC is required to provide any of its TOPs, upon their request to the RC, with SOL information pertaining to another TOP area that is within its RC's footprint. This is explained in the rationale for R5.5. Further information will be added to the rationale document as to why this may be useful. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need detailed information regarding another TOP's SOLs.

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

MEC supports MRO NSRF comments.

R3 Issues

A. Transmission Operators providing their SOLs to the Reliability Coordinator raises some questions for consideration by the SDT:

1. Is SOL data sharing being used for the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, R3 is redundant with the data specification in IRO-010-2 and could be a candidate for deactivation under the Standards Efficiency Review project.

2. If SOL data sharing is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to reliability of BPS, R3 saddles operations personnel with an administrative compliance burden that provides little reliability benefit.

B. SOLs, by definition, continuously change based on "*a specified system configuration*".

1. Is the expectation for the Transmission Operator to continuously provide the Reliability Coordinator with updated SOLs for each system configuration within the timeframe of each Operational Planning Analysis, Real-time monitoring and/or Real-time Assessment?

This highlights why the information/data exchange topic probably needs to remain within IRO-010-2 where Reliability Coordinators can determine items that need to be reported, the method and a timeframe based on the RCs' specific operating environment.

R5 Issues

A. Reliability Coordinators providing planning-based SOLs and IROLS to the Planning Coordinator and Transmission Planner raises some questions for consideration by the SDT:

1. What is the purpose of the Reliability Coordinator providing SOLs and IROLS to the Planning Coordinator and Transmission Planners?

If the purpose is to better align planning and operations, we are unaware of any requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments.

Concern. Without a clear requirement for the Planning Coordinator or Transmission Planner to use SOLs and IROLS in models for the Planning Assessments, R5 loads operations personnel with an administrative compliance burden that provides little reliability benefit.

2. Is the intent to use additional information--like SOLs and IROLs--identified during operations in the models for TPL-001-4 Planning Assessments?

If that is the case, MOD-032-1, the model building Standard, should be revised to expand the Applicability to include the Reliability Coordinator.

Compliance Challenge. Scattering model building Requirements across multiple Standards is inefficient, creating the opportunity for discord between Requirements, even difficulties agreeing on the guiding Requirement for purposes of compliance and enforcement. Clarity as to the expected or desired performance under a Requirement better serves BPS reliability.

B. Reliability Coordinators providing IROL information to the Transmission Operators raises some questions for consideration by the SDT:

1. Is IROL data sharing being used for the Transmission Operator's Operational Planning Analyses, Real-time monitoring and Real-time assessments?

If that is the case, then the data specification concept should be maintained and TOP-003-3 revised to allow the Transmission Operator to request and receive the information from its Reliability Coordinator.

2. If IROL data is not used by the RC for OPA, RTM and RTAs, what is the purpose of the data sharing, and the corresponding obligation by the Reliability Coordinator, to use the information?

Concern. Without a clear purpose and specific benefit to BPS reliability, R5 encumbers operations personnel with an administrative compliance burden that provides little reliability benefit.

3. The NSRF does not support incorporating R5 into FAC-014. As outlined, above, the revision may be inconsistent with the Standards Efficiency Review project goals of simplifying data exchange requirements and addressing redundancies.

Purpose Statement Issue

The NSRF does not support adding the phrase, "…and that Planning Assessment performance criteria is coordinated with these methodologies," to the proposed FAC-014-3 Purpose statement.

As already discussed in our previous responses, we believe consolidating the four FAC-015 requirements into proposed FAC-014-3 R6, R7 and R8 creates redundant Requirements; the planning aspects of the proposed Requirements are represented within other Standards. As such, the proposed revision to the FAC-014-3 Purpose statement is unnecessary.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC Supports NSRF Comments

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data spec. what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	2015-09_Unofficial_Comment_Form_202006 - SOCO Comments Final.pdf
Comment	
Detailed comments are in the attached file with special formatting for clarity and emphasis where needed (strike-through, highlighting, etc.).	
Likes 1	Mark Pratt, N/A, Pratt Mark
Dislikes 0	
Response	
Thank you for your comment. R5.1 and R5.2: Please see the explanation offered in the rationale for Requirements R5.1 and R5.2. The SDT believes that using the "upon written request" language may result in important SOL information not getting to the TP and RC such that they may not be aware of what to look for in their Planning Assessments to identify potential impacts to known stability issues or new issues that may arise. Requirements in the MOD and TPL standards do not cover the information with enough specificity for the RC to understand the necessary IROL and stability related information required to be provided under R5.2 See Q3 response to your suggestion regarding a new time horizon.	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement. R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement. R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.	
Steven Rueckert - Western Electricity Coordinating Council – 10	
Answer	
Document Name	
Comment	

Measure M3, the phrase "in accordance with its Reliability Coordinator's SOL methodology" should be stricken since it is stricken in the requirement. Proposed language "in accordance with requirement R3" would suffice.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This has been corrected.	
Mark Holman - PJM Interconnection, L.L.C. – 2	
Answer	
Document Name	
Comment	
R3 - The new language provides no suggested timeline beyond the Time Horizon of Operations Planning. Many SOLs, the limit itself, not the basis for the limit which can include Facility Ratings, at minimum, are derived/determined in the Real-time horizon. The Rationale gives several options/examples of how this might transpire which are not governed by the requirement language, which drops the suggested option of "*in accordance with its Reliability Coordinators SOL methodology*". As such, the proposed SDT language for R3 is ambiguous and either allows the TOP to indicate an SOL as they see fit, or continuously. Yet, the measurement indicates that evidence demonstrating the TOP provided its SOLs in accordance with its RC's SOL methodology. Which seems appropriate. R5 - RC's have Facility Ratings. RC's have stability limits. RC's have criteria for the determination of IROLs. The value of the SOL, which could include, for example a single temperature set rating for a given facility, is of minimal benefit to a PC or TP and is an incomplete set.	

· The methodology and ratings sets that can lead to potential SOLs would be of value to the PC or TP. As written, this requirement and many of its subparts serve minimal reliability value and is highly administrative in nature; and is not an improvement over the current FAC-014-2 R5. Requiring the formalized exchange of such information is not necessarily a determination that it is of value to the recipient. Suggest R5 be rewritten to align with R6 and provided the criteria, methodology and supporting data (including Facility Ratings) that may be both relevant and beneficial to a TP or PC. Alternatively, providing a list of SOL exceedances and/or trends may also be of some value to the PC or TP. A long list of SOLs with no additional context is an overlap of other requirements/obligations set on the TO/GOs in other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The time horizons for R3 are Operations Planning, Same-day Operations, Real-Time Operations as specified on the proposed clean version of the FAC-014-3 standard as linked to the 2015-09 Project page on the NERC website. In the requirement for R3, "in accordance with its RC methodology was removed", as provision of SOL information may be agreed upon through means other than within the methodology itself. See the rationale for R3 for more explanation. R5: This requirement is intended to be all encompassing in the areas of concern and give the RC the flexibility to work with PC and TPs to decide what is and isn't important information that should be shared within the terms mandated within the requirement.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	

Texas RE recommends the SDT consider the following:

- In Requirement R4, add "adjacent Reliability Coordinators Areas **within its Interconnection** or" unless it has an understanding that there is a need to confirm stability limits used in operations between RCs in different Interconnections.
- Revise Part 5.4 from "each established stability limit or each IROL" to "each established stability limit **and** each IROL applicable to the impacted Transmission Operator". Both the stability limit and the IROL should be provided to each impacted Transmission Operator.
- In Requirement R6, the term "System steady-state voltage limits" is not defined. Is this term intended to be different than the proposed term "System Voltage Limit," which was introduced in this project?
- Include a check and balance for use of the less limiting parameter in Requirement R6. This requirement allows for any criteria to be used (i.e. less limiting Facility Rating, etc) as it simply states a "technical rationale" has to be provided to any entity affected by a "less limiting" parameter.
- Requirement R6 uses "affected Transmission Planner, Transmission Operator and Reliability Coordinator," while R7 references "impacted Transmission Operator and Reliability Coordinator" and R8 references "impacted Transmission Owner and Generation Owner." Unless there is a specific reason for difference in verbiage, Texas RE recommends being consistent to avoid confusion and potential interpretation attempts at differences in language in the Requirements.
- Requirement R7 appears to exclude any CAP for Cascading or uncontrolled separation. Please provide the rationale for the exclusion.
- Provide more clarity in Requirement R8. In the phrase "any Facilities critical to the instability, Cascading or uncontrolled separation identified," it is not clear what would constitute "Facilities critical to the instability, Cascading or uncontrolled separation identified," and how these are different than "Facilities that comprise the Contingency(ies) (planning events only)."
- Requirement R8 requires the PC and TP to communicate "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified." Many of the updated Standards (e.g. CIP-014-3, FAC-003-5) use the applicability language "Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events". It would be helpful if the information provided by the PC and TP directly maps to the applicability section of these other Standards. Texas RE recommends requiring that communication to the TO and GO include "Facilities that if lost or degraded are expected to result in instances of

instability, Cascading, or uncontrolled separation, that adversely impacts the reliability of the Bulk Electric System for planning events" instead of "Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the instability, Cascading or uncontrolled separation identified."

- Requirement R8 uses the phrase "planning events only." Texas RE recommends including an explanation that these events refer to the events in Table 1 of TPL-001.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Requirement R4 as worded only speaks to stability limits that influence adjacent RC areas or more than one TOP in its area. If an adjacent RC is in another interconnection and won't be impacted, it may not need to be considered in the analysis; however, this requirement leaves room for where there may be such an impact via transfer levels on asynchronous tie-lines or unavailability of these tie-lines due to outages or a contingency. The rationale for R4 has been updated accordingly

R5.4 The SDT agrees with your suggestion.

The use of "System steady-state voltage limits" language was used to be consistent with TPL-001-4 R5 and makes use of the defined term "System" to clarify which steady-state voltage limits needed to be provided to the TP and PC and which are those are associated with System operation as opposed to operation of specific equipment. Use of the term is also is associated with the criteria that each PC and TP must follow in carrying out their Planning Assessment.

The reason the language surrounding the provision of the technical rationale was chosen was in hopes that the entities receiving it would engage the provider if they had concern around the merit of the rationale and work out an agreement. Stronger language around the confirmation of these rationales by either the RC or PC was avoided as both entities are on equal footing and one side should not have veto rights on such a rationale.

For R6 - R8, there was no intent to differentiate between impacted and affected system as worded in these requirements.

In requirement R7, there was no intention to avoid the use of cascading and uncontrolled separation with regards to corrective action plans. As cascading and uncontrolled separation is a result of instability, it falls under the same umbrella and is thus addressed by CAPs preventing instability.

Facilities that are critical to the derivation of IROLs can be different than what facilities comprise the contingencies. For example, a large generator or shunt capacitor which is not lost as part of a contingency triggering instability may play a big role in keeping healthy voltages on the system necessary to prevent instability occurring post-contingency.

Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joshua Andersen - Salt River Project - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	

The time horizon in R6-R8 are currently identified as "Long-Term Planning Horizon" While this aligns with the horizon of the TPL-001-4 standard where issues would be identified, it is specifically the Near-Term Planning horizon that these issues point to. We recommend

adjusting the time horizon assocoaited with R6-R8 to more accurately reflect the portion of the TPL-001-4 assessment they are intended to align to.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with you that near-term Planning is the timeframe at which these issues will be considered. However, there's no time horizon definition for near-term planning within the body of NERC standards. Therefore, the most appropriate time horizon was chosen, the Long-term Planning Horizon.	
Daniela Atanasovski - APS - Arizona Public Service Co. – 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	

NERC Standard IRO-17 obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. NERC TPL-001 includes the obligation that when the analysis indicates the inability of the system to meet the performance requirements. We believe FAC-014-3 R7 basically includes/requires the same if not similar information. If this additional detail is required, we suggest that IRO-017 be updated so that this type of request is located in a single requirement or standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. IRO-017 is specific to outage coordination whereas TPL-001 is specific to sharing with other planning entities but recognizes other entities, which may have a reliability, need. FAC-014-3 is about better coordination between Planning and Operating entities around specific aspects of the Planning Assessments and R7 in particular is about sharing details resulting from corrective action plans (CAPs) that would be of value to operations. Although there is probably some overlap in what will be shared, all three standards are focusing on a different aspect that's important for their intended purpose. The team recommends this concern is better looked at as part of a holistic review of standards efficiency.	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	
Document Name	
Comment	
NV Energy would like to communicate its additional concern over FAC-014-3, with the retirement of FAC-010-3. With the retirement of FAC-10-3, Transmission Planners will not be able to use their IROL methodology for the Planning Horizon anymore, and as stated, will be forced to adjust to their respective RC's SOL Methodology and definition of an IROL. NV Energy's concern with using a respective RC's IROL definition is the potential for the RC to identify an IROL for a more conservative loss than what a Transmission Planner would determine. NV Energy understands the need for a secure BES with the establishment of an IROL in an Interconnection; however, the ramifications of an IROL	

declaration stretch into multiple Standards that require a substantial amount of work for compliance implementation (i.e. CIP Standard suite), as well as the equipment modifications for facilities to monitor the flows on Elements within an IROL. NV Energy still believes their should still be a responsibility of defining IROLs with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The new FAC-014-3 standard allows the Planning entity to choose how to perform its assessments as long as the performance criterion used is as conservative as or more conservative than what's in the RC's SOL Methodology under the confines of TPL-001-4 requirements. The requirements for scope of coverage (consideration of elements out of service) that must be studied for planning assessments is specified in TPL-001-4.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	

Comment	
The SPP Standards Review Group offers the following "***non-content***" considerations for SDT review: 1. Implementation of the "blue box" concept, as in previous standards development processes, which could give industry insight on proposed revisions. 2. Consideration of the concept could assist in a seamless transfer of information to the future Guideline and Technical Basis documentation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. They will be considered by NERC staff.	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	

Document Name	
Comment	

The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale.

Bobbi Welch - Midcontinent ISO, Inc. – 2

Answer	
Document Name	
Comment	

MISO supports the comments filed by the IRC SRC.

The IRC SRC would like to note that discrepancies may be introduced when applying Facility Ratings derived in accordance with the RC's SOL methodology to the Near Term Transmission Planning Horizon because system topology may change from the time the Facility Ratings are

developed in the current year to the time when the limit is applied in the Planning Assessment of the Near Term Transmission Planning Horizon; a study of anticipated system performance one (1) to five (5) years in the future. Therefore, it is preferable to retain the process under TPL-001-4 "as is."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. – 2	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO – 2	
Answer	
Document Name	
Comment	

In addtion to comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee the CAISO has the following comments:

The SDT proposal to retire FAC-010 and the requirement to establish SOLs and IROLs for the planning horizon appear to be the result of the following two misconceptions:

- The “new” TPL 001-4 standard eliminates the need for developing SOLs and IROLs for the planning horizon, which is incorrect and
- SOLs are not useful for the reliable planning of the BES, which is also incorrect.

TPL 001-4 standard does not replace the need for developing SOLs and IROLs for the planning horizon and eliminate the need for the existing FAC-010 and Requirement R3 and R4 of the existing FAC-014. This is because TPL-001-4 is all about ensuring reliable service to firm load and firm transmission services. It does not require planning entities to stress tranfers on any part of the system to determine its limit. Also, since TPL-001-4 studies do not require stressing the system they are less suited to identifiying contingencies the lead to system instability,

cascading and uncontrolled separation compared to SOL and IROL Studies performed under FAC-014 R3 and R4. Even if, TPL 001-4 studies identify contingencies that lead to such adverse impacts, they would be mitigated, which means there would be no planning contingencies with such adverse impacts. SOLs are useful in the reliable planning of the system. For example, in the Western Interconnection (accepted) path ratings, which California ISO deems to be SOLs and are typically developed in the planning horizon, are used in the reliable planning of the system. In all its studies including the annual reliability assessment and local capacity studies, the CAISO ensures these SOLs are not exceeded. For example, reliability assessments and local capacity studies performed use this SOL information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT would like to understand specifically what discrepancies are being referred to in order to give a better answer to this question. However, based on what's been provided, the team feels that the only discrepancies from what is done today should result from more conservative facility ratings used in Operations that do not have a corrective action plan in place to increase them. The planning ratings used in these studies should generally always be equally or more restrictive unless there's an upgrade of the facility planned further out which is a justified reason for having a higher rating; this is true for how things are studied under the existing standards and are allowed under these new standards as well via a rationale. R7 is meant to capture and highlight in the Planning Assessment any instance where mitigation measures are used such that they do not hide limitations discovered. How far to stress the system and under what assumptions limitations are found in the planning horizon is something that is unique to each entity and was not part of FAC-010 and currently not part of TPL-001-4. Therefore, the team believes although there could be stronger requirements language to better address the concern, no gap was created in retiring FAC-010.	
Wayne Guttormson - SaskPower – 1	
Answer	
Document Name	
Comment	

Support the MRO-NSRF comments.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3: The SDT assumes you are referring to Operations Planning SOLs. This was a previously existing requirement that was moved. The SDT recognized the potential redundancy with IRO-010, which focuses on data specification and acknowledged that in its rationale document. However, as you've suggested further clarity in the rationale could be beneficial. Regarding your question in 1B, as identified in the rationale document around the proposed R3, the RC should include in their IRO-010 data specification what they need in terms of SOLs for all three categories mentioned and any additional SOL information outside of these categories can be specified under the proposed R3 requirement.

R5.1 R5.2: These existing requirements remain important even without FAC-010 so that Planning entities are aware of where system limitations exist within the Operating Horizon and how planned system changes in the near and long term planning horizon may impact them. Regardless of FAC-010, limitations in these horizons must be tested to determine system performance with the future system in mind. Planning SOL/IROLs as specified in FAC-010 were just a construct representing these limitations that need to be investigated and fully understood under TPL-001-4 and thus FAC-010 (and the construct of Planning based SOL/IROL) could be removed. Furthermore, the models associated with the SOLs and IROLs shared by the RC may or may not be required for consideration of these limitations in the Planning Assessment and would be at the discretion of the Planner of whether to request them through the MOD-32 specification. If required, they will have originated from the TO or GO themselves so provision through the existing channels created in the MOD-32 should not be an issue without the RC's involvement.

R5.3 R5.4: The rationale documentation around R5.3 and R5.4 describes the importance of this requirement is to ensure that the TOP has the value of the corresponding IROL or stability limit for each Operations time horizon. This information is critical to ensuring the TOP and the RC are working together to ensure cascading and uncontrolled separation do not occur. TOP-003-3 is a very non-specific requirement for the TOP and doesn't require the RC to fulfill the obligation to send the TOP IROL/stability information, which is key to maintaining reliable operation across our interconnections.

Kenya Streeter - Edison International - Southern California Edison Company – 6	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
No. Thank you	
Likes 0	
Dislikes 0	
Response	
Pamalet Mackey - Pamalet Mackey On Behalf of: James Mearns, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	

Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Marco Rios - Pacific Gas and Electric Company - 1	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

EXTENDED
Standards Announcement
Project 2015-09 Establish and Communicate System Operating Limits

Comment Period, Initial/Additional Ballots, and Non-binding Polls Now Open through August 26, 2020

Now Available

Recognizing the age of the project, NERC staff have reviewed the ballot pools that were formed in 2017 and 2018. Additionally, six non-binding polls did not reach quorum. Therefore, the comment period, initial/additional ballots, and non-binding polls, have been re-opened through **8 p.m. Eastern, Wednesday, August 26, 2020** for the following standards and implementation plan:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 – Transmission Operations
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- Implementation Plan

Commenting and Balloting
Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*

- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

UPDATED

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through August 3, 2020
Ballot Pools Formed through July 20, 2020

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, August 3, 2020** for the following standards and implementation plan:

- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, July 20, 2020.** ***NERC staff made the decision to re-open the older, existing ballot pools to allow stakeholders to join if desired.*** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial and additional ballots for the standards and implementation plan, along with non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 24 – August 3, 2020**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2015-09 Establish and Communicate System Operating Limits" in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through August 3, 2020
Ballot Pools Formed through July 20, 2020

Now Available

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- CIP-014-3 – Physical Security
- FAC-003-5 – Transmission Vegetation Management
- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-013-3 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, July 20, 2020** only for the newly added standards/initial ballots**.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

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Next Steps

Initial and additional ballots for the standards and implementation plan, along with non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 24 – August 3, 2020**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Applications" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

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CIP-014-3 Ballot Result Summary

Total Votes =	283
Total # of Ballot Pool=	337
Quorum =	83.98
Weighted Segment Vote=	60.75

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
74	1	99	1	43	0.581	31	0.419	1	8	16
6	2	8	0.6	5	0.500	1	0.100	0	2	0
59	3	77	1	36	0.610	23	0.390	1	3	14
11	4	17	1	6	0.545	5	0.455	0	2	4
55	5	74	1	29	0.527	26	0.473	0	6	13
42	6	51	1	22	0.524	20	0.476	0	4	5
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
6	10	6	0.6	4	0.400	2	0.200	0	0	0
255		337	6.4	147	3.888	108	2.512	2	26	54

CIP-014-3 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	LaTroy Brumfield		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A

1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Tho Tran	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A

1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A

3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Empire District Electric Co.	Kalem Long		None	N/A
3	Eversource Energy	Sharon Flannery		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A

3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Elizabeth Spivak		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	WEC Energy Group, Inc.	Janet OBrien		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Negative	Third-Party Comments
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Negative	Third-Party Comments
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A

6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

FAC-003-5 Ballot Result Summary

Total Votes =	283
Total # of Ballot Pool=	336
Quorum =	84.23
Weighted Segment Vote=	90.87

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
75	1	99	1	64	0.853	11	0.147	1	7	16
6	2	7	0.6	6	0.600	0	0.000	0	1	0
59	3	76	1	53	0.898	6	0.102	1	2	14
12	4	17	1	11	0.917	1	0.083	0	1	4
54	5	74	1	47	0.870	7	0.130	0	8	12
44	6	52	1	39	0.886	5	0.114	0	3	5
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
5	10	6	0.5	5	0.500	0	0.000	0	1	0
257		**336**	**6.3**	**227**	**5.725**	**30**	**0.575**	**2**	**24**	**53**

FAC-003-5 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A

1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A

1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	WEC Energy Group, Inc.	Janet OBrien		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

FAC-011-4 Ballot Result Summary

Total Votes =	272
Total # of Ballot Pool=	323
Quorum =	84.21
Weighted Segment Vote=	75.58

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
69	1	93	1	54	0.783	15	0.217	1	11	12
8	2	8	0.8	5	0.500	3	0.300	0	0	0
50	3	72	1	37	0.740	13	0.260	1	7	14
9	4	15	0.9	8	0.800	1	0.100	0	2	4
47	5	70	1	36	0.766	11	0.234	0	10	13
40	6	53	1	28	0.700	12	0.300	0	7	6
0	7	1	0	0	0.000	0	0.000	0	0	1
2	8	3	0.2	1	0.100	1	0.100	0	0	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
6	10	7	0.6	5	0.500	1	0.100	0	1	0
232		323	6.6	175	4.989	57	1.611	2	38	51

FAC-011-4 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A

1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A

1	TECO - Tampa Electric Co.	Regan Haines		Negative	Third-Party Comments
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Comments Submitted
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A

3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Modesto Irrigation District	Roderick Cook		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A

5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	Third-Party Comments
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A

6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

FAC-013-3 Ballot Result Summary

Total Votes =	273
Total # of Ballot Pool=	323
Quorum =	84.52
Weighted Segment Vote=	90.28

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
71	1	94	1	62	0.873	9	0.127	1	7	15
8	2	8	0.8	8	0.800	0	0.000	0	0	0
56	3	74	1	49	0.875	7	0.125	1	3	14
13	4	17	1	12	0.923	1	0.077	0	0	4
51	5	69	1	43	0.843	8	0.157	0	7	11
44	6	51	1	38	0.864	6	0.136	0	3	4
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
249		323	6.4	218	5.778	31	0.622	2	22	50

FAC-013-3 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	Comments Submitted
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted

3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A

5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted

5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A

6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

FAC-014-3 Ballot Result Summary

Total Votes =	272
Total # of Ballot Pool=	326
Quorum =	83.44
Weighted Segment Vote=	67.21

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
76	1	95	1	51	0.671	25	0.329	1	6	12
8	2	8	0.8	3	0.300	5	0.500	0	0	0
53	3	73	1	36	0.679	17	0.321	1	4	15
9	4	15	0.9	7	0.700	2	0.200	0	2	4
51	5	70	1	35	0.686	16	0.314	0	5	14
42	6	53	1	28	0.667	14	0.333	0	4	7
0	7	1	0	0	0.000	0	0.000	0	0	1
2	8	3	0.2	1	0.100	1	0.100	0	0	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
7	10	7	0.7	6	0.600	1	0.100	0	0	0
249		326	6.7	168	4.503	81	2.197	2	21	54

FAC-014-3 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted

1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted

1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Third-Party Comments
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Kent Feliks		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A

3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Modesto Irrigation District	Roderick Cook		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A

5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A

6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	Third-Party Comments
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A

6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

IRO-008-3 Ballot Result Summary

Total Votes =	217
Total # of Ballot Pool=	233
Quorum =	93.13
Weighted Segment Vote=	84.21

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
49	1	65	1	42	0.857	7	0.143	0	8	8
6	2	6	0.6	6	0.600	0	0.000	0	0	0
45	3	52	1	37	0.822	8	0.178	1	4	2
10	4	11	1	8	0.800	2	0.200	0	1	0
40	5	52	1	32	0.800	8	0.200	0	8	4
33	6	40	1	25	0.758	8	0.242	0	5	2
0	7	0	0	0	0.000	0	0.000	0	0	0
1	8	2	0.1	1	0.100	0	0.000	0	1	0
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	4	0.3	3	0.300	0	0.000	0	1	0
188		233	6.1	155	5.137	33	0.963	1	28	16

IRO-008-3 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A

1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted

3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Marcus Moor	Douglas Webb	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A

4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A

5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	James McBee	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

PRC-002-3 Ballot Result Summary

Total Votes =	283
Total # of Ballot Pool=	335
Quorum =	84.48
Weighted Segment Vote=	91.31

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
73	1	98	1	64	0.877	9	0.123	1	9	15
8	2	8	0.8	8	0.800	0	0.000	0	0	0
58	3	76	1	52	0.897	6	0.103	1	3	14
12	4	17	1	11	0.917	1	0.083	0	1	4
54	5	74	1	47	0.870	7	0.130	0	8	12
43	6	52	1	38	0.884	5	0.116	0	4	5
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
254		335	6.4	226	5.844	28	0.556	2	27	52

PRC-002-3 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	WEC Energy Group, Inc.	Janet OBrien		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

PRC-023-5 Ballot Result Summary

Total Votes =	283
Total # of Ballot Pool=	338
Quorum =	83.73
Weighted Segment Vote=	90.75

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
75	1	98	1	64	0.853	11	0.147	1	7	15
8	2	8	0.8	8	0.800	0	0.000	0	0	0
59	3	77	1	53	0.898	6	0.102	1	3	14
12	4	18	1	11	0.917	1	0.083	0	1	5
53	5	74	1	46	0.868	7	0.132	0	8	13
42	6	53	1	37	0.881	5	0.119	0	5	6
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	5	0.3	3	0.300	0	0.000	0	2	0
254		338	6.3	224	5.717	30	0.583	2	27	55

PRC-023-5 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	Comments Submitted
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted

3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A

3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A

5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	WEC Energy Group, Inc.	Janet OBrien		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A

6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

PRC-026-2 Ballot Result Summary

Total Votes =	283
Total # of Ballot Pool=	336
Quorum =	84.23
Weighted Segment Vote=	91.45

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
76	1	98	1	67	0.882	9	0.118	1	6	15
8	2	8	0.8	8	0.800	0	0.000	0	0	0
59	3	76	1	53	0.898	6	0.102	1	2	14
12	4	17	1	11	0.917	1	0.083	0	1	4
55	5	74	1	48	0.873	7	0.127	0	7	12
43	6	53	1	38	0.884	5	0.116	0	4	6
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
259		336	6.4	231	5.853	28	0.547	2	22	53

PRC-026-2 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joe McClung		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	No Comment Submitted
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	Comments Submitted
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Janet OBrien		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

TOP-001-6 Ballot Result Summary

Total Votes =	233
Total # of Ballot Pool=	250
Quorum =	93.20
Weighted Segment Vote=	84.49

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
60	1	73	1	52	0.867	8	0.133	0	5	8
6	2	6	0.6	6	0.600	0	0.000	0	0	0
51	3	55	1	42	0.824	9	0.176	1	1	2
12	4	12	1	10	0.833	2	0.167	0	0	0
47	5	55	1	37	0.787	10	0.213	0	4	4
35	6	42	1	26	0.743	9	0.257	1	3	3
0	7	0	0	0	0.000	0	0.000	0	0	0
1	8	2	0.1	1	0.100	0	0.000	0	1	0
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	4	0.3	3	0.300	0	0.000	0	1	0
216		250	6.1	178	5.154	38	0.946	2	15	17

TOP-001-6 Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Troy Hlavaty		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A

1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A

3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Negative	No Comment Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A

3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Marcus Moor	Douglas Webb	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A

5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A

6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Negative	No Comment Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	James McBee	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Implementation Plan Ballot Result Summary

Total Votes =	273
Total # of Ballot Pool=	325
Quorum =	84.00
Weighted Segment Vote=	55.98

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
73	1	95	1	39	0.534	34	0.466	0	9	13
8	2	8	0.8	3	0.300	5	0.500	0	0	0
55	3	74	1	28	0.509	27	0.491	0	4	15
10	4	14	1	7	0.700	3	0.300	0	1	3
52	5	71	1	27	0.519	25	0.481	0	5	14
42	6	53	1	20	0.476	22	0.524	0	5	6
0	7	0	0	0	0.000	0	0.000	0	0	0
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
5	10	6	0.5	4	0.400	1	0.100	0	1	0
247		**325**	**6.5**	**130**	**3.639**	**117**	**2.861**	**0**	**26**	**52**

Implementation Plan Ballot Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	LaTroy Brumfield		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer		Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		None	N/A

1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Third-Party Comments
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Kent Feliks		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Modesto Irrigation District	Roderick Cook		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Third-Party Comments
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	Cleco Corporation	Stephanie Huffman		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Elizabeth Spivak		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A

5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	Comments Submitted
6	Colorado Springs Utilities	Melissa Brown		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Muscatine Power and Water	Nick Burns		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	Third-Party Comments
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Third-Party Comments
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Third-Party Comments
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

CIP-014-3 Non-binding Poll Result Summary

Total Votes =	264
Total # of Ballot Pool=	324
Quorum =	81.48
Non-Binding Poll Weighted Segment =	58.50

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
59	1	94	1	34	0.576	25	0.424	0	18	17
4	2	8	0.4	4	0.400	0	0.000	0	4	0
50	3	77	1	31	0.620	19	0.380	0	10	17
8	4	16	0.8	5	0.500	3	0.300	0	4	4
43	5	69	1	23	0.535	20	0.465	0	14	12
31	6	50	1	15	0.484	16	0.516	0	11	8
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	5	0.3	3	0.300	0	0.000	0	2	0
200		324	5.7	117	3.615	83	2.085	0	64	60

CIP-014-3 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	California ISO	Jamie Johnson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted

3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted

3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Daniel Frank	Andrey Komissarov	None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A

5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Negative	Comments Submitted
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A

6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

FAC-003-5 Non-binding Poll Result Summary

Total Votes =	264
Total # of Ballot Pool=	323
Quorum =	81.73
Non-Binding Poll Weighted Segment =	88.32

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
57	1	93	1	49	0.860	8	0.140	0	20	16
4	2	7	0.4	4	0.400	0	0.000	0	3	0
48	3	76	1	44	0.917	4	0.083	0	11	17
9	4	16	0.9	8	0.800	1	0.100	0	3	4
42	5	70	1	36	0.857	6	0.143	0	16	12
31	6	51	1	27	0.871	4	0.129	0	12	8
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
197		323	5.9	174	5.304	23	0.596	0	67	59

FAC-003-5 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A

3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A

3	WEC Energy Group, Inc.	Thomas Breene		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A

5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A

5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A

6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

FAC-011-4 Non-binding Poll Result Summary

Total Votes =	253
Total # of Ballot Pool=	311
Quorum =	81.35
Non-Binding Poll Weighted Segment =	79.26

Total # of A +N Votes	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
53	1	87	1	41	0.774	12	0.226	0	20	14
6	2	8	0.6	5	0.500	1	0.100	0	2	0
42	3	74	1	34	0.810	8	0.190	0	14	18
9	4	14	0.9	8	0.800	1	0.100	0	2	3
38	5	67	1	31	0.816	7	0.184	0	15	14
31	6	49	1	23	0.742	8	0.258	0	11	7
0	7	1	0	0	0.000	0	0.000	0	0	1
2	8	3	0.2	1	0.100	1	0.100	0	0	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
6	10	7	0.6	5	0.500	1	0.100	0	1	0
188		311	6.4	149	5.141	39	1.259	0	65	58

FAC-011-4 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A

2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A

3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A

5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A

5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A

6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

FAC-013-3 Non-binding Poll Result Summary

Total Votes =	254
Total # of Ballot Pool=	313
Quorum =	81.15
Non-Binding Poll Weighted Segment =	86.98

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
54	1	90	1	47	0.870	7	0.130	0	19	17
6	2	8	0.6	6	0.600	0	0.000	0	2	0
45	3	74	1	40	0.889	5	0.111	0	12	17
10	4	16	1	9	0.900	1	0.100	0	2	4
40	5	66	1	33	0.825	7	0.175	0	14	12
31	6	49	1	26	0.839	5	0.161	0	11	7
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
192		313	6.2	167	5.523	25	0.677	0	62	59

FAC-013-3 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		None	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A

1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A

1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A

3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A

6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A

8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax	Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Abstain	N/A

FAC-014-3 Non-binding Poll Result Summary

Total Votes =	253
Total # of Ballot Pool=	314
Quorum =	80.57
Non-Binding Poll Weighted Segment =	72.82

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
56	1	88	1	40	0.714	16	0.286	0	18	14
6	2	8	0.6	3	0.300	3	0.300	0	2	0
44	3	74	1	33	0.750	11	0.250	0	12	18
9	4	14	0.9	7	0.700	2	0.200	0	2	3
40	5	68	1	30	0.750	10	0.250	0	13	15
31	6	50	1	22	0.710	9	0.290	0	10	9
0	7	1	0	0	0.000	0	0.000	0	0	1
2	8	3	0.2	1	0.100	1	0.100	0	0	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
6	10	7	0.6	5	0.500	1	0.100	0	1	0
195		314	6.4	142	4.624	53	1.776	0	58	61

FAC-014-3 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A

1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A

1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A

3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Negative	Comments Submitted
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A

4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A

5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	David Weber		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted

8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Negative	Comments Submitted

IRO-008-3 Non-binding Poll Result Summary

Total Votes =	204
Total # of Ballot Pool=	223
Quorum =	91.48
Non-Binding Poll Weighted Segment =	81.17

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
42	1	62	1	34	0.810	8	0.190	0	15	5
5	2	6	0.5	5	0.500	0	0.000	0	1	0
38	3	52	1	31	0.816	7	0.184	0	9	5
9	4	10	0.9	7	0.700	2	0.200	0	1	0
30	5	48	1	24	0.800	6	0.200	0	13	5
25	6	38	1	19	0.760	6	0.240	0	9	4
0	7	0	0	0	0.000	0	0.000	0	0	0
1	8	2	0.1	1	0.100	0	0.000	0	1	0
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	4	0.3	3	0.300	0	0.000	0	1	0
154		223	5.9	125	4.885	29	1.015	0	50	19

IRO-008-3 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A

1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A

3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	Westar Energy	Marcus Moor	Douglas Webb	Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A

4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A

5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	James McBee	Douglas Webb	Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A

8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax	Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Abstain	N/A

PRC-002-3 Non-binding Poll Result Summary

Total Votes =	264
Total # of Ballot Pool=	326
Quorum =	80.98
Non-Binding Poll Weighted Segment =	88.78

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
58	1	93	1	51	0.879	7	0.121	0	18	17
6	2	8	0.6	6	0.600	0	0.000	0	2	0
50	3	77	1	45	0.900	5	0.100	0	10	17
10	4	17	1	9	0.900	1	0.100	0	2	5
43	5	70	1	37	0.860	6	0.140	0	14	13
32	6	51	1	28	0.875	4	0.125	0	11	8
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
205		326	6.2	182	5.615	23	0.585	0	59	62

PRC-002-3 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		None	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A

3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A

3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A

5	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A

6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

PRC-023-5 Non-binding Poll Result Summary

Total Votes =	263
Total # of Ballot Pool=	327
Quorum =	80.43
Non-Binding Poll Weighted Segment =	88.50

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
58	1	93	1	50	0.862	8	0.138	0	18	17
6	2	8	0.6	6	0.600	0	0.000	0	2	0
49	3	77	1	45	0.918	4	0.082	0	11	17
10	4	17	1	9	0.900	1	0.100	0	2	5
41	5	70	1	35	0.854	6	0.146	0	16	13
31	6	52	1	27	0.871	4	0.129	0	11	10
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	5	0.3	3	0.300	0	0.000	0	2	0
200		327	6.1	177	5.505	23	0.595	0	63	64

PRC-023-5 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		None	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A

3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A

3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A

5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Abstain	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

PRC-026-2 Non-binding Poll Result Summary

Total Votes =	263
Total # of Ballot Pool=	326
Quorum =	80.67
Non-Binding Poll Weighted Segment =	89.16

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
58	1	93	1	51	0.879	7	0.121	0	18	17
6	2	8	0.6	6	0.600	0	0.000	0	2	0
49	3	76	1	45	0.918	4	0.082	0	10	17
10	4	17	1	9	0.900	1	0.100	0	2	5
43	5	71	1	37	0.860	6	0.140	0	15	13
31	6	51	1	27	0.871	4	0.129	0	11	9
0	7	1	0	0	0.000	0	0.000	0	0	1
1	8	3	0.1	1	0.100	0	0.000	0	1	1
1	9	1	0.1	1	0.100	0	0.000	0	0	0
4	10	5	0.4	4	0.400	0	0.000	0	1	0
203		326	6.2	181	5.629	22	0.571	0	60	63

PRC-026-2 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey		None	N/A
1	CMS Energy - Consumers Energy Company	Donald Lynd		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A

1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Troy Hlavaty		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	None	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A

3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	Rutherford EMC	Tom Haire		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	Seminole Electric Cooperative, Inc.	Michael Lee		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Avani Pandya	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted

5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A

5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A

6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

TOP-001-6 Non-binding Poll Result Summary

Total Votes =	217
Total # of Ballot Pool=	238
Quorum =	91.18
Non-Binding Poll Weighted Segment =	85.21

Total # of A +N Vot	Segment	Ballot Pool	Segment Weight	Positive Votes	Positive Fraction	Negative Votes with Comments	Negative Fraction	Negative Votes without Comments	Abstentions	No Vote (non-response)
48	1	68	1	40	0.833	8	0.167	0	14	6
5	2	6	0.5	5	0.500	0	0.000	0	1	0
42	3	55	1	37	0.881	5	0.119	0	8	5
10	4	11	1	8	0.800	2	0.200	0	1	0
33	5	51	1	28	0.848	5	0.152	0	13	5
26	6	40	1	21	0.808	5	0.192	0	9	5
0	7	0	0	0	0.000	0	0.000	0	0	0
1	8	2	0.1	1	0.100	0	0.000	0	1	0
1	9	1	0.1	1	0.100	0	0.000	0	0	0
3	10	4	0.3	3	0.300	0	0.000	0	1	0
169		238	6	144	5.170	25	0.830	0	48	21

TOP-001-6 Non-binding Poll Result Details

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dairyland Power Cooperative	Renee Leidel		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Troy Hlavaty		None	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Eversource Energy	Sharon Flannery		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Trevor Tidwell		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Marcus Moor	Douglas Webb	Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Dwayne Parker		Affirmative	N/A

4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Neil Shockey		Negative	Comments Submitted
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NovaSource Power Services	Bradley Collard		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A

5	Pacific Gas and Electric Company	James Mearns	Pamalet Mackey	None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell	Tess Neshem	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	James McBee	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
45-day formal comment period with additional ballot	October 2020
10-day final ballot	December 2020
NERC Board adoption	February 2021

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**
    4.1. Functional Entities:
    4.1.1. Planning Coordinator
    4.1.2. Reliability Coordinator
    4.1.3. Transmission Operator
    4.1.4. Transmission Planner
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria	described in its respective Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed

			in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
45-day formal comment period with additional ballot	October 2020
10-day final ballot	December 2020
NERC Board adoption	February 2021

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs ~~in accordance with its Reliability Coordinator's SOL methodology~~.

R4. Each Reliability Coordinator shall establish stability limits when ~~the limit~~an instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit ~~or~~and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

~~5.5~~5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

~~**R7.**~~**R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

~~**R8.**~~**R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

~~R10.~~R8. Each Planning Coordinator and each Transmission Planner shall annually communicate ~~any instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System identified in its Planning Assessment of the Near-Term Transmission Planning Horizon~~ to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause ~~. This communication shall include those Facilities that comprise the Contingency(ies) (planning events only) and any Facilities critical to the~~ instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon~~identified~~. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

~~M9.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology") as established in FAC-011-4.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria	described in its respective Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed

			in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 - Establish and Communicate System Operating Limits
- FAC-003-5 - Transmission Vegetation Management
- PRC-002-3 - Disturbance Monitoring and Reporting Requirements
- PRC-023-5 - Transmission Relay Loadability
- PRC-026-2 - Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 - Establish and Communicate System Operating Limits
- FAC-003-4 - Transmission Vegetation Management
- PRC-002-2 - Disturbance Monitoring and Reporting Requirements
- PRC-023-4 - Transmission Relay Loadability
- PRC-026-1 - Relay Performance During Stable Power Swings
- TOP-001-5 - Transmission Operations
- IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of

the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-5, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC-002-2, PRC-023-4, and PRC-005-3 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
  - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
  - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the TO or the RC.

- *PRC-023-4: Time Period to address new designations is retained:*
  - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- *PRC-002-3, Requirement R5*
  - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.
- *PRC-023-5*
  - Each Planning Coordinator shall conduct its first assessment under PRC-023-5 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4, whichever occurs first.
- *PRC-026-2*
  - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they most complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
  - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
  - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 - Establish and Communicate System Operating Limits
- ~~CIP-014-3 Physical Security~~
- FAC-003-5 - Transmission Vegetation Management
- ~~FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~
- PRC-002-3 - Disturbance Monitoring and Reporting Requirements
- PRC-023-5 - Transmission Relay Loadability
- PRC-026-2 - Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary ~~of Terms Used in NERC Reliability Standards~~

Requested Retirement(s)

- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 - Establish and Communicate System Operating Limits
- ~~CIP-014-2 Physical Security~~
- FAC-003-4 - Transmission Vegetation Management
- ~~FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~
- PRC-002-2 ~~-~~- Disturbance Monitoring and Reporting Requirements
- PRC-023-4 - Transmission Relay Loadability
- PRC-026-1 - Relay Performance During Stable Power Swings
- TOP-001-5 - Transmission Operations
- IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is ~~twelve~~ twenty-four (24~~12~~) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is ~~twelve~~ twenty-four (~~12~~24) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2~~, CIP-014-2~~, FAC-003-4, ~~FAC-013-2,~~ PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-~~6~~5, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4~~, CIP-014-2~~, PRC-002-2, PRC-023-4, and PRC-005-3 are incorporated herein by reference and shall remain applicable to FAC-003-5, ~~CIP-014-3,~~ PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
  - o A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
  - o Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - o Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.

- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
    - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the TO or the RC.
- *PRC-023-4: Time Period to address new designations is retained:*
    - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- ~~*FAC-013-2*~~
    - ~~Following effective date of FAC-013-3, the Planning Coordinator shall update their methodology and perform their assessment either:~~
        - ~~Within the calendar year the standard becomes effective if the assessment was not completed that calendar year under FAC-013-2~~
        - ~~Within the next calendar year after the standard is effective if the assessment had been completed within that calendar year under FAC-013-2~~
- ~~*CIP-014-3*~~
    - ~~Following effective date of FAC-013-3, the Transmission Owner shall perform the risk assessment Required in Requirement R1 within~~
        - ~~30 calendar months of its last assessment if it had identified one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection in that prior assessment; or~~
        - ~~60 calendar months of its last assessment if it had not identified any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.~~
- *PRC-002-3, Requirement R5*
    - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.

- *PRC-023-~~4~~5*
    - Each Planning Coordinator shall conduct ~~t~~its first assessment under PRC-023-~~4~~5 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-~~3~~4, whichever occurs first.
- *PRC-026-2*
    - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they most complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
    - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
    - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

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Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** by **8 p.m. Eastern, December 7, 2020.**

Additional information is available on the project page [project page]. If you have questions, contact Senior Standards Developer, [Latrice Harkness], (via email), or at 404-446-9728.

Background Information

The Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. One of the primary objectives of Project 2015-09 is to make changes to the FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards and the revised definitions of Operational Planning Analysis (OPA) and Real-time Assessments (RTA).

In order to maintain consistency with CIP-002 criteria language, the standard drafting team (SDT) will not be modifying CIP-014 during this project. The applicability language regarding the derivation of IROLs will not be changed in CIP-014. The SDT has made significant enhancements in the Facilities Design, Connections, and Maintenance (FAC), Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs). NERC is still evaluating approaches to the CIP-002 and CIP-014 language.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. Do you agree with the 24-month Implementation Plan?

   ☐ Yes
   ☐ No

   Comments:

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

   ☐ Yes
   ☐ No

   Comments:

3. If you have any other comments regarding FAC-014-3 and the Implementation Plan that you haven’t already provided, please provide them here.

   Comments:

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Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
<u>FAC-014-2, Requirement R1</u> R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	<u>Requirements R1, R2, and R4 of FAC-014-3</u> R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when an instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

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Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

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	planning any portion of the Reliability Coordinator Area; <u>FAC-014-3 Requirement R6:</u> **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning	

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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that	

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	may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.

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FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	1. FAC-014-3, Requirements R7 2. TPL-001-4, Requirement R8 FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a

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	instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the	PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-014-3, Requirement R7 (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are

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		communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL m~~M~~ethodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology (SOL ~~M~~methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology. R4. Each Reliability Coordinator shall establish stability limits ~~to be used in operations~~ when ~~the limit~~an instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL ~~M~~methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL ~~M~~methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL ~~M~~methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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		the RC did not ensure that the TOP's SOL was consistent with its SOL ~~M~~methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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Coordinator Area that are consistent with its Reliability Coordinator's SOL ~~M~~methodology.	with its Reliability Coordinator's SOL ~~M~~methodology.	understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL ~~M~~methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL ~~M~~methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL ~~M~~methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3~~015-1~~, Requirement~~s~~ ~~R7~~R6 ~~R1 – R3~~ FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: ~~*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*~~ **9.2** Each of the following entities ~~30 days~~ prior to the effective date of the SOL methodology ~~or as soon as practicable if a change must be~~	The SDT is proposing a construct that does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL ~~M~~methodology. The PCs and T~~O~~Ps responsible for planning any portion of the RC's Area are made aware of the RC's SOL ~~M~~methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL ~~M~~methodology, PCs and TPs who plan any portion of the System in the

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	~~implemented in less than 30 days to address a reliability issue~~: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area; FAC-014-3~~015-1~~ Requirement R7~~6R1 – R3~~: **R~~7~~6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for	RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. ~~New Reliability Standard FAC-015-1 along with the changes in the P~~proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3~~015-1~~, Requirement~~s~~ R7~~6~~ ~~R1 – R3~~ ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those ~~established in accordance~~ described within the RC's SOL ~~M~~methodology. ~~FAC-015-1, Requirement R1 addresses Facility Ratings, Requirement R2 addresses the System steady state voltage limits, and Requirement R3~~

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	any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator. ~~1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~	~~addresses the stability performance criteria used in Planning Assessments. These requirements~~ FAC-014-3, Requirement R~~7~~6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability. ~~By implementing Requirements R1 – R3 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations.~~

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~• The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan,~~ ~~• Facility Rating differences are due to variations in ambient temperature assumptions,~~ ~~• The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator, or~~ ~~• The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.~~ ~~2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability~~	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~Coordinator's SOL Methodology. The process may allow the use of less limiting System steady-state voltage limits if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ • ~~The Planning Coordinator provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Planning Coordinator and Reliability Coordinator.~~ ~~Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. The~~	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~process may allow the use of less limiting stability performance criteria if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ ~~• The Planning Coordinator provides a technical rationale for using a less limiting stability performance criterion to each affected Transmission Planner and Reliability Coordinator, or~~ ~~• The Transmission Planner provides a technical rationale for using a less limiting stability performance criterion to each affected Planning Coordinator and Reliability Coordinator.~~	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities)	~~Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1.~~ While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3,

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information: R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) FAC-014-3, Requirement R5: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies);	Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	5.2.5. A description of ~~the associated~~ system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.~~5~~ 6 for each established stability limit ~~or~~and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested	

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	SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies. IRO-014-3, Requirement R1 R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its	

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	Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator~~ in accordance with its Reliability Coordinator's SOL Methodology~~.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.~~ The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states:~~
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission	1. FAC-014-3~~015-1~~, Requirements ~~R7, R8R6,~~ R7 ~~R1 – R4~~ 2. TPL-001-4, Requirement R8	Provision of important planning study information to TOPs and RCs is preserved in ~~Reference the Ddescription and Change Justification above for Requirements R3 and R4, which describes a different set of roles and responsibilities~~

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Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	FAC-014-3~~015-1~~ Requirements ~~R76, R87~~ ~~**R1 – R3**~~ (Also ~~S~~see the ~~T~~translation above for Requirements R3 and R4~~ section above.~~) **R7.** Each Planning Coordinator and each Transmission Planner shall annually~~(?)~~ communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism, or unacceptable damping);	~~for the PC and TP as defined in FAC-014-3015-1, R7.~~ ~~FAC-014-3015-1, Requirements R76 R1 – R3 results in PCs and TPs using Facility Ratings, System steady state voltage limits criteria, and stability performance criteria in their Planning Assessments of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the crtieria for Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance described within the RC's SOL Methodology.~~ FAC-014-3~~015-1~~, Requirement R7, which~~4~~ requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability~~, Cascading or uncontrolled separation~~ identified in ~~the~~ its Planning Assessments ~~and Transfer Capability assessments~~ to each impacted ~~RCs, TOPs, TOs, and GOs~~ TOP and RC. The subparts of Requirement R7~~4~~ require the communication of key information that

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	7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. ~~**R4.** Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include:~~ ~~**4.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~	can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. ~~This information is also necessarily communicated to TOs and GOs for their use in identifying Facilities that require higher levels of vegetative management or cyber protection.~~ TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	~~4.2 The associated stability criteria used as part of determining the instability;~~ ~~4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;~~ ~~4.4 A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified;~~ ~~4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;~~ ~~4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~ TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning	

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	Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple	FAC-014-3~~015-1~~, Requirement ~~R4~~ ~~R8~~R7 (See the Translation above for Requirements R5.3 and R5.4 ~~section above.~~)	FAC-014-3~~015-1~~, Requirement ~~R6~~ ~~R8~~7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3~~015-1~~, Requirement ~~R4~~ ~~R8~~7 addresses not only the identification of multiple contingencies that result in stability criteria violation ~~limits~~, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7

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contingencies, the Planning Authority shall so notify the Reliability Coordinator.		ensures the type of instability, ~~relevant~~ the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation ~~assumptions used by the PC~~ are communicated by the PC to the appropriate TOP and RC. • ~~Additionally, FAC-015-1, Requirement R4 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation.~~ • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC ~~in accordance with FAC-015-1, Requirement R4~~. ~~In addition~~Further, it may be noted that FAC-014-2, Requirement R6,

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		R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3~~015-1~~, Requirement ~~R4s~~ R~~8~~7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology ("SOL methodology") as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**Medium**
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	**Medium**

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology ("SOL ~~M~~methodology") as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.~~65~~6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	Medium~~High~~
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~mingle More than One Obligation~~	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria. ~~N/A~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	**Medium**

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement ~~R5.3 and~~R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

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VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 -and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Technical Rationale for Reliability Standard FAC-014-3

October 2020

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP “shall establish SOLs (as directed by its Reliability Coordinator)” because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been “directed to by their RC.” This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC’s SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC’s documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC’s SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC.   It’s important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when an instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

RCs who have asynchronous connections should consider the impact of all possible transfer levels across those connections including when those connections are not available if lost by contingency or forced outage.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, R5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required by R4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need more information from the RC on related SOLs in other TOP areas within the region that could impact their derivation. Requirement R5, Parts 5.3 through 5.5, require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and 4.1.1.4 in CIP-014. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models. Analysis of these models determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:
Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor allow the PCs nor TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement. The obvious example for such an exception is a facility where the PC / TP has assumed an upgrade which increases the Facility Rating (typically, the thermal limit) of the equipment in question.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans, or the use of ambient temperature assumptions in seasonal planning models that differ from those ambient weather assumptions used in operational analyses and monitoring in real time, may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases due to upgrade are appropriately included in future planning models. These provisions should be included in the documented technical rationale provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable

System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Existing FAC-014-2, Requirement R6 requires similar, though less detailed, information is shared by the planning with the RC. The SDT believes FAC-014-3, Requirement R7, improves upon this requirement and provides added clear and concise information to its impacted RCs and TOPs.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation that adversely impacts the reliability of the BES to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Rationale R8

This requirement was drafted to ensure the appropriate details (i.e. Facilities) regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. This is necessary to ensure owners receive this input to identify the Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT’s proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners.

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through December 7, 2020

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, December 7, 2020** for the following standard and implementation plan:

- FAC-014-3 – Establish and Communicate System Operating Limit
- Implementation Plan

Commenting and Balloting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, along with the non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 27 – December 7, 2020**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2015-09 Establish and Communicate System Operating Limits" in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

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Comment Report

Project Name:	Project 2015-09 Establish and Communicate System Operating Limits | FAC-014-3 and Implementation Plan
Comment Period Start Date:	10/23/2020
Comment Period End Date:	12/7/2020
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 4 ST 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 4 OT

There were 60 sets of responses, including comments from approximately 139 different people from approximately 107 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the 24-month Implementation Plan?

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

3. If you have any other comments regarding FAC-014-3 and the Implementation Plan that you haven't already provided, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Nick Fogleman	Prairie Power Incorporated	1,3	SERC
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO

					David Hartman	Arizona Electric Power Cooperative	1	WECC
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered	5	NPCC

	Solutions International Inc.		
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
Chantal Mazza	Hydro Quebec	2	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC

					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC
					John Pearson	ISONE	2	NPCC
					John Hastings	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO

1. Do you agree with the 24-month Implementation Plan?

Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While we do appreciate the Standards Drafting Team's proposal of the 24-month rather than the originally proposed 12-month Implementation Plan, we still believe 36 months would be more appropriate. As stated previously, the proposed changes are very expansive and involve many individuals across a number of Functional Entities. In addition, new cross-functional procedures and processes would need to developed and established to meet the proposed obligations. Once again, we believe 36 months would be more appropriate.	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
While AEPC appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, AEPC believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement. AEPC also signed on to ACES comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
While ACES appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, ACES believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement.	
Likes 0	
Dislikes 0	

Response	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS supports the change from 12-months to the 24-month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	Yes
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The MRO NERC Standards Review Forum (MRO NSRF) supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	Yes
Document Name	

Comment

MPC supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	Yes

Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Yes, Oncor agrees with the 24-month Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Entergy supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern Company supports the proposed 24-month Implementation Plan.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon supports the proposed 24-month Implementation Plan.

Submitted on behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	Yes
Document Name	

Comment

The ISO/RTO Council Standards Review Committee (IRC/SRC) supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Evergy - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 1.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Ameren agrees with and supports EEI commnets

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the proposed 24-month Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Brooks - Reliable Energy Analytics LLC - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nurul Abser - NB Power Corporation - 1,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Ellis - Pacific Gas and Electric Company - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT appreciates the Standard Drafting Team's revisions to FAC-014-3, Requirement R8, in response to the last round of comments. However, ERCOT believes Requirement R8 should be further clarified in order to remove an ambiguity that exists in the current draft.

In Requirement R8, the word "impacted" is ambiguous (impacted by what?) because the requirement also refers to "instability, Cascading or uncontrolled separation." As written, the requirement can be interpreted as implying an impact to virtually everything in a particular interconnection. It is unclear whether Requirement R8 is intended to mean that only the owners of the facilities that comprise the planning event contingency(ies) that cause "instability," as identified in the near-term planning assessment, need to be notified that certain specific facilities they own are part of a planning event contingency that would cause "instability." If this is the correct interpretation, which ERCOT believes to be the case, ERCOT suggests Requirement R8 provide as follows in order to remove the ambiguity:

R8. Each Planning Coordinator and each Transmission Planner shall annually provide each Transmission Owner and Generation Owner that owns Facilities that are part of one or more planning event Contingencyies that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES, as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon, a list of the Transmission Owner's or Generation Owner's Facilities that are part of each planning event Contingency that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES. [Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]

Alternatively, confirmation from NERC in the form of guidance accompanying FAC-014-3 may be helpful in clarifying the scope of Requirement R8.

ERCOT further notes that it intends to vote in favor of a revised FAC-014-3, provided the scope of Requirement R8 is further clarified.

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	

If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), ACES believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy is supporting MRO NSRF comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO

Answer	No
Document Name	

Comment

The Southwest Power Pool (SPP) Regional Transmission Organization (RTO) agrees the proposed language in requirement 5.6 plays a role in the reliability of the Bulk Electric System (BES), however, SPP RTO recommends the Reliability Coordinators (RCs) communication to the Transmission Owners (TOs) and Generation Owners (GOs) of facilities could be incorporated into an IRO Reliability Standard, possibly IRO-009, based on the contribution potential of the derivation of Interconnection Reliability Operating Limits (IROL's), and/or IRO-010 which contains actions for the RC to operate within IROLS and contain the requirements for the RC and asset owners to communicate information for IROLs.

SPP RTO interrupts that the FAC Reliability Standards are intended for specifying what the RC needs to include in the methodology to calculate System Operating Limits (SOLs) and IROLs. In a requirement such as 5.6, the calculation for IROL could confuse the communication of the obligations of asset owners to the RC.

SPP recommends the proposed modification of the 5.6 requirement language:

The original language states "*identified as critical to the derivation of an IROL*" and SPP is proposing "*identified by the RC as critical to the derivation of an IROL*".

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

FAC-014-3, Part 5.6

The IRC SRC notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the IRC SRC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be an appropriate location. The latter being the case, the IRC SRC recommends the time horizon for Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies ***at least once every twelve calendar months.***

Finally, if the derivation of an IROL and its associated critical contingencies is considered temporary, we ask for clarification whether these facilities become subject to requirements under CIP-002-5.1a. There is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The IRC SRC asks the SDT exclude the ability of temporary IROLs from triggering CIP-002-5.1a, Attachment 1, Medium Impact Rating provisions. This could be accomplished by defining the time horizon for Criterion 2.6, similar to what has been done with Criterion 2.3; i.e. "as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3, measure M5 allows information to be provided via posting to a secure website. As FAC-014-3 is not directly applicable to Generator Owners (section 4), they may not even be aware that they would need to check their Reliability Coordinator's website for this posting and that they would need to check it on a daily basis should the Same-day Operations and Real-Time Operations time horizons for R5 be retained.

FAC-014-3, Requirement 8

The IRC SRC notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC0-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a. Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3 is not directly applicable to Generator Owners.

FAC-014-3, Measurement 3

The byproduct of removing "in accordance with its Reliability Coordinator's SOL methodology" to align with Requirement 3 language, introduces an inconsistency with similar FAC-014-3 language around each of its other Requirements and Measures and which is not justified by the Rationale which effectively makes it an option to include or not include the language within an RC's SOL methodology.

Doing so effectively allows for a TOP to provide their SOLs to the RC in any timeframe of their choosing, so long as they are provided. While the SDT Rationale points to potential duplicity or alignment with that of IRO-010-2 and thus the need for flexibility through the removal of "in accordance with its Reliability Coordinator's SOL methodology", IRO-010-2 makes no direct reference to System Operating Limits. As such, the IRC SRC believes "in accordance with its Reliability Coordinator's methodology" to be appended to both R3 and M3.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

1. Does this mean PC/TPs need to have "adverse impact" criteria in their Annual Assessment or does this return to the concept of any failure to meet TPL-001-4/5 System performance requirements of Table 1? As an alternative to all of this confusion, why not simply mirror the concept and clear language in Requirement R7:

   Requirement R8 - Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities identified as part of a Corrective Action Plan(s) developed to address any that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company agrees with the addition of requirement R5.6 as well as the revisions to measure M3.

While the revised wording in requirement R8 is an improvement to the the previous posting, Southern Company believes that this requirement could result in burdensome communication even if there isn't any identified issues per the Planning Assessment to communicate. As such, Southern Company recommends the addition of the following sentence at the end of Requirement R8:

"Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication".

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 0	
Dislikes 0	
Response	

Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	

Jamie Johnson - California ISO - 2	
Answer	No

Document Name	
Comment	

CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), AEPC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry.

AEPC also signed on to ACES comments.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment

Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

MPC agrees with and supports the MRO NERC Standards Review Forums comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning

Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

The addition of the term ‘critical’ to R5.6 makes this revision difficult to support and impossible to ensure compliance. ‘Critical’ is not a defined term in the NERC Glossary - consider removing the term 'critical' or adding term to the NERC Glossary. The term critical was also inserted into R 5.2.4.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

I'm supporting MRO NSRF comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.

Likes 0	
Dislikes 0	
Response	

Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	No
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	

Support the MRO-NSRF comments for R5.6 and M3.

Recommend removing Req 8 or addressing the issue directly in CIP 002 or FAC 003. It is unclear how TO's and GO's would use this information as presented otherwise.

For FAC-003, with the retirement of FAC-010- 3 the PC is not resposible for identifying IROLs, and the language for '**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.' should be changed to denote the RC.

For CIP-002 '**2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.' the reference to PC should be removed.

Likes 0	
Dislikes 0	

Response

Kjersti Drott - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State does not believe the revisions provide clear instruction. R5.6 language could be improved within the context of IROL development. 'Critical' to the derivation of an IROL is ambiguous and requires further clarification to ensure uniform interpretation and implementation.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP is supportive of R5.6 as the proposed requirement clearly aligns and supports criteria outlined in CIP-002 and CIP-014. This requirement should remove any previous ambiguities that may have occurred in identifying facilities that are critical to the derivation of an IROL and its associated contingencies.

AEP is also supportive of R8 as proposed as this will ensure GO's and TO's receive information for Facilities within their systems that could lead to instability/cascading and would create a more clear line of sight for those entities to take action on identified facilities accordingly to reduce potential risk of future instability/cascading. It should be noted however, the Corrective Action Plan and critical facility reports proposed within R7 and R8 are direct outcomes of TPL-001-4 requirements and should instead be included in that standard, if in any at all. There is no benefit having requirements pertaining to the reporting of planning studies scattered across different families of standards.

AEP would like to make a suggestion and encouragement regarding how the standards drafting team provides redlined documents for industry review. While redlined documents using the previously proposed revision as a baseline do provide a very beneficial way for the reader to identify only the most-recently proposed changes, we believe that they cannot be the only redlined document provided during these comment and balloting periods. These particular redlines are simply a "delta" between the current and previous draft revision and do NOT show all the proposed additions and deletions that have been retained-to-date. This could result in the reader misunderstanding or misinterpreting the content in the draft. For example, text shown in black could be a) text currently included in the version under enforcement or b) new text that was proposed in a previous comment period but "no longer considered new text" in the current comment period. In addition, text shown as deleted could be a) text that has been newly proposed for deletion in the current comment period or b) text that was proposed for addition in a previous comment period draft but then later struck from consideration in a latter comment period. As a result, when multiple revisions are proposed over time, the reader would have to review each and every draft proposed to date and somehow determine for themselves all the changes retained to date. A balloter is not voting on only the most recently proposed changes, they are voting on all the proposed changes that have been retained-to-date. As a result, we recommend drafts showing only most recent changes also be accompanied by an additional redlined document which shows *all the proposed revisions retained to date*, and using the version under enforcement as a baseline.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

See prior NCPA and John Allen City Utilities prior balloting comments

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

See prior NCPA and John Allen City Utilities prior balloting comments.

Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG support NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees that the addition of Requirement R5, part 5.6 enhances and clarifies the obligations of the RC under requirement R5. This change also supports GO and TO CIP compliance activities for CIP-002 and/or CIP-014. However, the reference within the FAC-014-3 Technical Rationale, on the top of page 6, incorrectly references "4.1.1.4 in CIP-014." This reference should be 4.1.1.3 (see below).

Excerpt from FAC-014-3 Technical Rationale, Page 6 (Rationale R5)

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and/or **4.1.1.4 in CIP-014**. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC.

CIP-014-2

Applicability Section

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies**.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

EEI supports the modification to Measure M3.

EEI supports the changes made to Requirement R8, which address our earlier concerns and provides clear requirements for Planning Coordinators and Transmission Planners that define what they must communicate to impacted TOs and GOs whenever planned contingency events indicate that

instability, Cascading and uncontrolled separation would occur resulting in negative impacts to BES reliability in the Near-Term Transmission Planning Horizon.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 2.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We agree with the revisions, however, please consider revising and renumbering the R5.2 sub-requirements as follows:	

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL and the associated Contingeny(ies);

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI).

Submitted on behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	Yes
Document Name	

Comment

Requirement R5.6 does not reference any schedule or frequency. Reclamation recommends adding a required communication cycle to align with the language in Requirement R5.2, to ensure that GOs and TOs have access to updated information, and to provide the RCs with greater confidence in responses received from entities that must document the lack of Facilities critical to the derivation of an IROL for CIP-002. Reclamation recommends the following language:

Change from:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

To:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies **at least once every twelve calendar months**.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	Yes
Document Name	

Comment

In regards to requirement R8, BC Hydro requests that the drafting team confirm if it the intent was to include the extreme events (as referenced on page 11 in Table 1 of TPL-001-4) when determining the "list of Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon"?

Including the extreme events for consideration under the FAC-014-3 R8 appears to be an expansion of the current requirement R6 of FAC-014-2, which only references multiple contingencies per TPL-003 (not including extreme events, which were covered in TPL-004 System Performance under Extreme Events prior to TPL-001-4 becoming effective).

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

FAC-014-3, R5.6

FAC-014-3, Part 5.6 modifies and expands the existing FAC-014-2 to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies.

Facilities identified as critical to the derivation of an IROL and its associated contingencies is a criterion for applying a Medium Impact Rating under CIP-002-5.1a. The proposed requirement R5.6 is redundant and we suggest that there is no reliability need to expand FAC-014-2 with the proposed R5.6.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS does not have comments for the revised measurement M3 of FAC-014-3. AZPS does not have comments for the the added requirement 5.6 as it currently does not impact AZPS however may have potential impact in the future. AZPS does not have comments for R8.	
Likes 0	
Dislikes 0	
Response	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Ellis - Pacific Gas and Electric Company - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nurul Abser - NB Power Corporation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Brooks - Reliable Energy Analytics LLC - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned there is no timeline for the provision of the list of Facilities in the new Requirement R5.6. Texas RE suggests being consistent with Requirements 5.1 and 5.2 which specify "at least once every twelve calendar months." Texas RE also recommends capitalizing "Contingency(ies)" since it is defined in the NERC Glossary.

For Requirement R8, Texas RE inquires as to whether it is intended that all lines "that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES" that are communicated to the GO or TO under R8 would be applicable to FAC-003-5. FAC-003-5 section 4.2.2 states "Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event."

Texas RE reads this language to require all overhead transmission lines operated below 200 kV communicated by Planning Coordinators and Transmission Planners comprising planning event Contingencies causing instability, Cascading, or uncontrolled separate to remain subject to the FAC-003-5 vegetation management requirements. However, Texas RE is concerned that, for a planning event that involves multiple Contingencies (P3 – P7), the standard could be read to exclude single Facilities associated with the event by virtue of the fact that the loss of the individual Facility does not result, by itself, in instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System. Texas RE believes that such a reading could result in a reliability gap if individual Facilities under 200 kV that contribute to instability, Cascading, or uncontrolled separation in planning studies are arguably not included within the scope of FAC-003-5. Accordingly, Texas RE requests that the SDT clarify that it did not intend to exclude such Facilities from the scope of the FAC-003-5 vegetation management requirements.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Neil Shockey - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

Please see comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

3. If you have any other comments regarding FAC-014-3 and the Implementation Plan that you haven't already provided, please provide them here.

Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	
Document Name	
Comment	
No other comments	
Likes 0	
Dislikes 0	
Response	

John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	

City Utilities of Springfield appreciates the 2015-09 team's consideration of our previous comments. We understand the desire to complete this five year old project, but respectfully disagree that additional changes are not necessary. We believe that current projects should not continue creating requirements that are either unclear, redundant or out of place in the body of Reliability Standards. This is contrary to all the efforts industry is putting forward in the Standards Efficiency Review project. Therefore, City Utilities stands firm on our previous comments.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP is concerned by the usage and meaning of “stability criteria” within R6, and request that the SDT provide clarity regarding the exact meaning of this phrase. Does it mean the acceptable power swing damping level and transient voltage dip and recovery durations? Does it mean the bare necessity for the system to remain stable? Does it mean the P1-P7 contingency definitions used in studies to evaluate stability? Does it mean the stability SOLs themselves? Uncertainty regarding the exact meaning of this phrase leads us to offer the following feedback…

If “stability criteria” means stability SOLs themselves, then the following feedback paragraph applies. The RC must deal with real-time outages, often simultaneous multiple outages that may result in more restrictive stability operating limits than are considered in planning studies. Example: the RC secures system against P4 stuck CB events during other real-time outages. In planning, prior outages are not required to be simulated by the TPL standard for P4 events, nor have they been regarded as necessary for P4 event planning purposes in the past. Depending on a RC’s SOL methodology, the proposed R6 may impose more restrictive limits on planning studies, and for this reason, might result in corrective action plans and expense that would not have been identified in the past. R6 may also result in complication and confusion between planning and operations because it may never be clear out of the numerous outage conditions encountered by operations in any day, season, or year, which of these must be considered in planning studies under the proposed R6. It is also quite likely that particular combinations of outages will never appear again, rendering planning studies that are forced to recognize SOLs resulting from such outage combinations as “more limiting stability criteria” not very relevant.

If “stability criteria” means the acceptable power swing damping level and transient voltage dip and recovery durations, or the bare necessity for the system to remain stable, or the P1-P7 contingency definitions used in studies to evaluate stability then the following feedback paragraph applies. The RCs, PCs, and TPs most probably already have (and in our experience *do* have) coordinated power swing damping criteria and would have consistent transient voltage criteria should that ever be applied in operations. There is no valid reason to require this in FAC-014. The performance measure requiring system stability to be maintained is the same by definition in both operations and planning. Contingency event definitions are also the same between operations and planning. If there are no other stability criteria to be coordinated between RC and PC/TP, the proposed R6 may be useless for stability planning purposes and will only cause needless administrative paperwork.

In addition, real-time generation redispatch is often assumed in planning studies to resolve instability and it is not always considered a Corrective Action Plan. Real-time generation redispatch may be particularly relevant to P6 scenarios as “system adjustments” as distinguished from “corrective action plans.” Thus, real-time redispatch may either result in no corrective action plan because it is not considered a corrective action plan (nullifying R7) or, as a system adjustment, will result in no planning event instability, cascading, or uncontrolled separation (nullifying R8). The reliability benefit of the proposed R7 and R8 may be nullified if generation redispatch is used to resolve instability.

AEP recommends removal of “stability criteria” from the proposed R6 and transfer of the proposed R7 and R8 over to a TPL-001 Standards Drafting Team. While well intentioned, we believe the Project 2015-09 Standards Drafting Team is unintentionally encroaching on the TPL domain by proposing R7 and R8 be placed within FAC-014. These requirements are best served if drafted and reviewed from a Transmission Planner perspective which can properly evaluate their necessity in view of the potential for nullification by possible reliance on operational actions and system adjustments not considered corrective action plans.

While we obviously do not yet know the answers to the “stability criteria” question we have posed above, we would like to propose the following revisions to R6 which we believe may provide clarity and minimize compliance burden...

Each Planning Coordinator and each Transmission Planner shall ~~implement a documented process to~~ ~~use~~ *incorporate* Facility Ratings, System steady-state voltage limits and stability limits ~~criteria~~ in its Planning Assessment of Near Term Transmission Planning Horizon ~~that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator’s SOL methodology~~ *as identified in Requirement 5.1 and 5.2.*

• The Planning Coordinator may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

In the event that the formatting used for our suggested revisions to R6 (showing both our deleted and added text) are not retained by the SBS system, we provide it here again, showing only the retained and added text in a “clean format.”

Each Planning Coordinator and each Transmission Planner shall incorporate Facility Ratings, System steady-state voltage limits and stability limits in its Planning Assessment of Near Term Transmission Planning Horizon as identified in Requirement 5.1 and 5.2.

• The Planning Coordinator may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

The compliance burden is minimized by simply requiring the PC/TP to incorporate RC ratings and limits in TPL assessments instead of requiring yet another process document for what should be a straightforward comparison check. Emphasizing Requirements R5.1 and R5.2 in R6 clarifies the responsibility of the PC/TP. R5.1 and R5.2 provide the PC/TP specific SOL/IROL/stability limits from the RC that can be incorporated into Planning Assessments. Only referencing an RC's SOL methodology as originally proposed in R6 could lead to much interpretation by the PC/TP since they are only methodology documents. In addition, from a stability perspective, requiring the PC/TP to evaluate specific stability events as identified by the RC in R5.1/R5.2 provides a finite set of events to be considered for the Planning Assessment. It is possible that some of the stability limits from the RC will not satisfy Planning Assessment criteria, but using R5.1/R5.2 as the point of reference provides structure to the Planning Assessment process.

Likes 0	
Dislikes 0	

Response

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Glen Allegranza - Imperial Irrigation District - 1,3,5,6

Answer	
Document Name	

Comment

no comments

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	

Document Name	
Comment	

The current effective standard FAC-014-2 version, Requirement 5.1.3 states “The associated Contingency(ies)”. The proposed FAC-014-3, Requirement 5.2.4, states “The associated critical Contingency(ies).” What distinguishes a “critical” contingency(ies)?

Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	
Document Name	
Comment	

No Additional comments

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	
Comment	

R6: Techincal rational seems inconsistent with how the language as written could be read. Requirement does give the RC authority over the PC in it sets a performance requirement for the PC to meet outside of the TPL standard. It seems to pre-suppose that the PC's criteria and the Facility Ratings it uses may be suspect. Suggest the SDT draft language for the RC to simply submit its SOL methodology and ratings and perhaps more importantly the basis to the PC for review and comment. The PC can then determine what is applicable for its planning assessment.

Likes 0	
Dislikes 0	
Response	

Jerry Horner - Basin Electric Power Cooperative - 6

Answer	

Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

{C}· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

{C}· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

R6:

The SDT agreed with BPA's previous comments to the proposed revisions.The SDT noted that the Technical Rationale would be revised to ensure this clarity was captured and explained. BPA's concern is that the Technical Rationale is apart from the Standard and would likely not be used by the auditors. BPA believes this language needs to be explicitly stated in the Standard.

Additionally, after further review of the SDT's proposed language, BPA does not agree with using the term "criteria" before Facility Ratings.

SDT Proposed Language for R6:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

BPA recommends the following edits to add clarity to the STD's proposed R6 revisions. BPA also believes '***system voltage limits'*** should not be capitalized, as it is not defined in the NERC Glossary of Terms. (Bold, italic text for additions):

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that Facility Ratings and system voltage limits*** *used* in its Planning Assessment of the Near Term Transmission Planning Horizon are equally limiting or more limiting than the ***Facility Ratings and system voltage limits provided by the TOP to its RC in accordance with*** its Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for stability specified in its respective Reliability Coordinator's SOL methodology.*** *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

BPA has no suggested changes to the R6 bullets below.

• The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

R7:

BPA appreciates the SDT incorporating the language *"…that adversely impacts the reliability of the Bulk Electric System…"* into the modified R8. BPA's other comments were in response to Corrective Action Plans. BPA does not believe that the addition of language in R8 satisfies our concerns with R7. BPA believes R8 is a subset of R7.4 where R7.4 is related to the contingency event, and R8 is related to the facilities that comprise the contingency event.

BPA believes it should only be required to communicate/report information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. Corrective Action Plans for local issues within a TP's system that do not impact the reliability of the Bulk Electric System should not have to be communicated/reported. As R7 is currently written, all Corrective Action Plans would need to be communicated/reported. This is consistent with the SDT's response to comments from earlier postings.

BPA suggests modifying R7 with the following language below (bold, italic text added) to avoid the burden of communicating/reporting on local issue Corrective Action Plans. By making this change, enitities will only be required to report Corrective Action Plans that affect the larger BES.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Draft 3 of this standard added requirements for the quality of transmission assessments performed per TPL-001. In particular, R6 calls for Near Term Transmission Planning to use Facility Ratings and Voltage Limits that are equally or more limiting than in the Reliability Coordinator's SOL methodology. Also, R7 calls for Planning Coordinators and Transmission Planners to annually communicate selected results of the Near-Term Transmission Planning results with Transmission Operators and Teliability Coordinators.

Ideally, requirements R6 and R7 need to be in TPL-001 instead of FAC-014.

Likes 0	
Dislikes 0	

Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suggests modifying the term "an instability", as contained in Requirement R4, to "an identified instability". This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

Dominion Energy requests the SDT clarify the addition of the word "critical" to describe Contingency(ies)" noting that "critical Contingency(ies)" is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For Dominion Energy to support this change, the term "critical Contingency(ies)" need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term "critical Contingency(ies)".

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Dominion Energy disagrees with the inclusion of “as established in FAC-011-4” within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, “The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System.” The rationale document also states (following on from the earlier quote), “This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC’s SOL methodology.”

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

· FAC-011-4 uses the phrase, “System Voltage Limits” (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as “System steady state voltage limits” as well as “System Voltage Limits”. The MRO NSRF recommends that consistent terminology be used across these standards.

· FAC-011-4 uses the phrases, “stability limits”, and “stability performance criteria” (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as “stability criteria” or just “stability”. The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Jamie Johnson - California ISO - 2

Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	

Neil Shockey - Edison International - Southern California Edison Company - 5

Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

Please see comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Oliver Burke - Entergy - Entergy Services, Inc. - 1

Answer	
Document Name	

Comment

N/A - Entergy supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment	
NIPSCO endorses the other comments on R6, R7, and R8 provided by AEP on 11/24/2020. And reiterates our prior NIPSCO comments provided 7/31/2020.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments, noted by section.

Implementation Plan – Effective Date sectionn

- There is a missing delimiter (") around System Operating Limit (shows *"System Voltage Limit" and System Operating Limit"* but should be *"System Voltage Limit" and "System Operating Limit"*).

Implementation Plan - Prior Implementation Plans section:

- PRC-005-3 is referenced and it seems that it should reference PRC-005-6.
- Texas RE recommends noting that there have been changes to the language of FAC-003-5 to include the TP as an entity that can designate a line and also uses the language "identified the line in Applicability under 4.2" instead of "designates the line as being an element of an IROL". Texas RE agrees this change should not significantly modify the application of the implementation plan.
- For FAC-003-5 "Newly Designated Lines" - There seems to be some ambiguity about what happens to the lines newly designated under FAC-003-4 Applicability Section 4.2 language in the last year of applicability for FAC-003-4. Do those lines receive an additional year of non-applicability because the new version of the Standard is being applied?
- For PRC-002-3, "TO" and "RC" should be spelled out to be consistent.

Implementation Plan - Additional Provisions section:

- For FAC-014-3 Requirement R6, Texas RE recommends a clear date by which the Planning Assessment must reflect the implementation of Requirement R6 (e.g 24 calendar months after effective date). The language "when it begins its next cycle for conducting the studies to support its Planning Assessment" for R6 is not measureable and may lead to inconsistent understanding and application.

Additional FAC-014-3 Comments:

- Texas RE noticed the SDT added the word “critical” in in FAC-014-3 5.2.4. Texas RE is concerned that since there is no criteria or definition of the word critical, inconsistencies could arise between entities regarding the meaning of “critical” which, in turn, could lead to perceived inconsistencies in monitoring. Texas RE recommends drafting clear criteria to determine “critical” to ensure reliability. While it was added to accommodate the 5.6 language addition there is no clear meaning of the word or intent. When reviewed in audit space there will be a need to understand what “critical” means to an entity and how they derived, and applied, the thought process.
- In Requirement R6, there should be a hyphen in “Near Term”. This is consistent with the NERC Glossary Term.

Texas RE continues to be concerned with the following:

- The asterisk on FAC-003 Table 2 appears to be inconsistent with FAC-014. The asterisk is applicable only “if PC has determined such per FAC-014.” FAC-014 includes both of the PC and TP in Requirements R6-R8. The footnote as written excludes the TP so it is unclear whether TP Facilities, determined per FAC-014 R8, are subject to vegetation management. This could leave a gap in the reliable operations of the grid if the list of Facilities derived by the PC and TP are different. Texas RE recommends adding “and TP” to the footnote in FAC-003-5.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

For Requirements R5 and R8, Reclamation recommends that the SDT consider adding an annual notice to the TOs and GOs that do not own impacted Facilities. This would increase transparency and provide direct evidence of the lack of impact.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company disagrees with the revision to R4. The revision creates unnecessary confusion compared to the original language, seeming to imply that each Reliability Coordinator shall establish stability limits only after an instability event that impacts adjacent Reliability Coordinator Areas has occurred. As such, if the revision is to remain, the following revision is suggested to clarify that this is a proactive coordination, not reactive:

Revise from “an instability” to “an *identified* instability”.

Southern Company disagrees with Requirement R5.2.2, as the modifications to the requirement create unnecessary ambiguity. Specifically, Southern Company disagrees with the inclusion of the word “derivation” in R5.2.2 as there can be a significant number of Facilities across the Interconnections needed to accurately model and simulate a stability event and therefore are critical to the “derivation” of a stability limit. It is suggested instead that “derivation” be defined or replaced with “establishment” to better clarify those Facilities that should be identified.

While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 “Establish and Communicate System Operating Limits” should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.

FAC – 014 R7 and R8 could result in burdensome communication even if there isn’t any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

- Modify the last sentence of FAC-014 R7 from “This communication shall include:” to “This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:”.
- Add another sentence at the end of R8, as also suggested in Comment Form Question 2 above: “Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication”.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI).

Submitted on behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	
Document Name	

Comment

thank you

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

FAC-014-3 Comments

Requirement 6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."

The IRC SRC agrees with previously provided comments from the IRC SRC that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on GOs and TOs. Additionally, from a Planning study perspective TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to comments submitted by the IRC SRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. The IRC SRC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

The IRC SRC also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The IRC SRC recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The IRC SRC recommends that consistent terminology be used across these standards.

Finally, the IRC SRC recommends that the following ***change*** be made to R6 to clarify the intent of the requirement:

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, ***System Voltage Limits*** and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the ***use of*** Facility Ratings, System Voltage Limits and stability ***criteria*** described in its respective Reliability Coordinator's SOL methodology.

Requirement 7

FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. The IRC SRC recommended IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. The SDT response to this request is that the IRO-17 standard deals with outage coordination (and not SOLs) that FAC-014 is the proper place for SOL transmittal and related information between entities. Additionally, the SDT acknowledges that they discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. The IRC SRC disagrees as the information required in FAC-014 R7 is included in TPL-001 assessments. Requirement 2.7 of TPL-001 requires that the assessment identify the Corrective Action Plan for instances where the analysis indicates the inability to meet the performance requirements. Obligating the Planning Coordinator and Transmission Planner to only communicate Corrective Action Plans for instability issues falls short of information that would be important for Transmission Operators and Reliability Coordinators. As such, updated TPL-001 to provide the report in its entity to Transmission Operators and Reliability Coordinators provides a more holistic view of all Corrective Action Plans that may be forthcoming to the system. As such, the IRC SRC recommends that TPL-001 R8 be modified to specifically include Transmission Operators and Reliability Coordinators.

FAC-011-4

Finally, the IRC SRC would like the drafting team to confirm in a response to comments or the technical rational document that FAC-011-4, Part 6.4 only applies to addressing overloads that are observed in a planning or forecasted timeframe and Part 6.4 would not restrict the RC from taking actions in Real-time if the planned mitigating actions are ineffective or insufficient to address an impending IROL exceedance. This observation is made based on the reference to time horizon being identified as 'Operations Planning' and the use of *planned* manual load shedding

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	
Document Name	

Comment

Please consider if revisions to section "C. Compliance" are necessary to update FAC-014-3 with the current NERC wording for the Compliance section. For example, "Compliance Enforcement Authority" could be abbreviated as CEA in the Compliance section.

RE: Violation Severity Levels, R1, Severe VSL: Please consider removing, "as established in FAC-011-4" since this reference appears to be unnecessary.

RE: Technical Rationale for Reliability Standard FAC-014-3, Rationale R5, part 5.6: Please consider correcting the reference to 4.1.1.4 in CIP-014 to read as 4.1.1.3 in CIP-014.

Requirement 6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."

NPCC RSC believes that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on the GO and/or TO. Additionally, from a Planning study perspective, TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to the previous comments from the SRC IRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. NPCC RSC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

NPCC RSC also recommends the following additional changes to the language in the requirement:

{C}· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady-state voltage limits" as well as "System Voltage Limits". We recommend that consistent terminology be used across these standards.

{C}· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". We recommend that consistent terminology be used across these standards.

Finally, NPCC RSC recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Douglas Webb - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 3.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with and supports EEI commnets

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy supports MRO NSRF's additional comments:

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding

Likes 0	
Dislikes 0	

Response

Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
None and thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI suggests modifying the term “an instability”, as contained in Requirement R4, to “an identified instability”. This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

EEI requests the SDT clarify the addition of the word “critical” to describe Contingency(ies)” noting that “critical Contingency(ies)” is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For EEI to support this change, the term “critical Contingency(ies)” need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term “critical Contingency(ies)”.

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

EEI disagrees with the inclusion of “as established in FAC-011-4” within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG support NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response

Ed Hanson - Pacific Gas and Electric Company - 5

Answer	
Document Name	

Comment

No comments

Likes 0	

Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	

Comment
None.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name: Project 2015-09 Establish and Communicate System Operating Limits | FAC-014-3 and Implementation Plan

Comment Period Start Date: 10/23/2020

Comment Period End Date: 12/7/2020

Associated Ballots: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 4 ST
2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 4 OT

There were 60 sets of responses, including comments from approximately 139 different people from approximately 107 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the 24-month Implementation Plan?

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

3. If you have any other comments regarding FAC-014-3 and the Implementation Plan that you haven't already provided, please provide them here.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO
					Bobbi Welch	Omaha Public Power District	1,3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Bobbi Welch	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
New York Independent	Gregory Campoli	2		ISO/RTO Standards	Gregory Campoli	NYISO	2	NPCC

System Operator				Review Committee	Helen Lainis	IESO	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Nick Fogleman	Prairie Power Incorporated	1,3	SERC

					Susan Sosbe	Wabash Valley Power Association	3	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
					David Hartman	Arizona Electric Power Cooperative	1	WECC
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC

					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC

				Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
				Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
				Salvatore Spagnolo	New York Power Authority	1	NPCC
				Shivaz Chopra	New York Power Authority	5	NPCC
				Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
				Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
				Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
				Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC

					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC

					John Pearson	ISONE	2	NPCC
					John Hastings	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Yasser Bahbaz	Southwest Power Pool Inc.	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO

1. Do you agree with the 24-month Implementation Plan?	
Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	

Answer	No
Document Name	
Comment	
While we do appreciate the Standards Drafting Team's proposal of the 24-month rather than the originally proposed 12-month Implementation Plan, we still believe 36 months would be more appropriate. As stated previously, the proposed changes are very expansive and involve many individuals across a number of Functional Entities. In addition, new cross-functional procedures and processes would need to developed and established to meet the proposed obligations. Once again, we believe 36 months would be more appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
While AEPC appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, AEPC believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement. AEPC also signed on to ACES comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
While ACES appreciates the SDT's proposal of 24-months rather than the initial proposal of a 12-month Implementation Plan, ACES believes a 36-month timeframe would be more appropriate as the proposed changes are time intensive to implement.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. We have consulted numerous industry stakeholders, which resulted in the revised proposal for a 24-month Implementation Plan. Since a large portion of the respondents has suggested this timeframe may be lengthy enough to accomplish implementation, the SDT will suggest a 24-month plan in the final posting.	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS supports the change from 12-months to the 24-month implementation plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	Yes
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NERC Standards Review Forum (MRO NSRF) supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Johnson - California ISO - 2	
Answer	Yes

Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	

Yes, Oncor agrees with the 24-month Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Entergy supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the proposed 24-month Implementation Plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed 24-month Implementation Plan. Submitted on behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (IRC/SRC) supports the changes made by the SDT to extend the Implementation Plan from 12 to 24 months.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
EEI supports the proposed 24-month Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Brooks - Reliable Energy Analytics LLC - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nurul Abser - NB Power Corporation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Ellis - Pacific Gas and Electric Company - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

2. The SDT acted on industry comments and revised FAC-014-3 by adding requirement R5.6 and revising measure M3 and requirement R8. Do you agree with the revisions?

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT appreciates the Standard Drafting Team's revisions to FAC-014-3, Requirement R8, in response to the last round of comments. However, ERCOT believes Requirement R8 should be further clarified in order to remove an ambiguity that exists in the current draft.

In Requirement R8, the word "impacted" is ambiguous (impacted by what?) because the requirement also refers to "instability, Cascading or uncontrolled separation." As written, the requirement can be interpreted as implying an impact to virtually everything in a particular interconnection. It is unclear whether Requirement R8 is intended to mean that only the owners of the facilities that comprise the planning event contingency(ies) that cause "instability," as identified in the near-term planning assessment, need to be notified that certain specific facilities they own are part of a planning event contingency that would cause "instability." If this is the correct interpretation, which ERCOT believes to be the case, ERCOT suggests Requirement R8 provide as follows in order to remove the ambiguity:

R8. Each Planning Coordinator and each Transmission Planner shall annually provide each Transmission Owner and Generation Owner that owns Facilities that are part of one or more planning event Contingencyies that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES, as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon, a list of the Transmission Owner's or Generation Owner's Facilities that are part of each planning event Contingency that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES. [Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]

Alternatively, confirmation from NERC in the form of guidance accompanying FAC-014-3 may be helpful in clarifying the scope of Requirement R8. ERCOT further notes that it intends to vote in favor of a revised FAC-014-3, provided the scope of Requirement R8 is further clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is considering clarifications in the rationale for Requirement R8 to ensure the intent of the requirement is clear. The term "impacted" is used several times in the SDT-proposed version of FAC-014 in R5 and R7 as well. The use of this term in R8 is consistent with those other instances in that a measure of specificity was needed in the determination of the subset of TO and GO entities to send information to. The term was thus included to clarify that only the TO and GO with identified facilities would be included in the communication from the PC & TP. This term was added to the text of R8, in part, as a response to comments to previous postings where commenters brought up the concern that the prior wording of R8 could be interpreted as including all TO and GO entities regardless of whether their Facilities were identified by the PC or TP.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	

If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), ACES believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard. A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5 which addresses RC communication requirements of SOLs (including IROLs).	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy is supporting MRO NSRF comments: **FAC-014-3, Part 5.6** The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day***	

Operations and Real-Time Operations (with emphasis on the latter time horizons), the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
The Southwest Power Pool (SPP) Regional Transmission Organization (RTO) agrees the proposed language in requirement 5.6 plays a role in the reliability of the Bulk Electric System (BES), however, SPP RTO recommends the Reliability Coordinators (RCs) communication to the Transmission Owners (TOs) and Generation Owners (GOs) of facilities could be incorporated into an IRO Reliability Standard, possibly IRO-009, based on the contribution potential of the derivation of Interconnection Reliability Operating Limits (IROL's), and/or IRO-010 which contains actions for the RC to operate within IROLS and contain the requirements for the RC and asset owners to communicate information for IROLs. SPP RTO interrupts that the FAC Reliability Standards are intended for specifying what the RC needs to include in the methodology to calculate System Operating Limits (SOLs) and IROLs. In a requirement such as 5.6, the calculation for IROL could confuse the communication of the obligations of asset owners to the RC. SPP recommends the proposed modification of the 5.6 requirement language: The original language states "*identified as critical to the derivation of an IROL*" and SPP is proposing "*identified by the RC as critical to the derivation of an IROL*".	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5 which addresses RC communication requirements of SOLs (including IROLs).	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

FAC-014-3, Part 5.6

The IRC SRC notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the IRC SRC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be an appropriate location. The latter being the case, the IRC SRC recommends the time horizon for Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies ***at least once every twelve calendar months.***

Finally, if the derivation of an IROL and its associated critical contingencies is considered temporary, we ask for clarification whether these facilities become subject to requirements under CIP-002-5.1a. There is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The IRC SRC asks the SDT exclude the ability of temporary IROLs from triggering CIP-002-5.1a, Attachment 1, Medium Impact Rating provisions. This could be accomplished by defining the time horizon for Criterion 2.6, similar to what has been done with Criterion 2.3; i.e. "as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3, measure M5 allows information to be provided via posting to a secure website. As FAC-014-3 is not directly applicable to Generator Owners (section 4), they may not even be aware that they would need to check their Reliability Coordinator's website for this posting and that they would need to check it on a daily basis should the Same-day Operations and Real-Time Operations time horizons for R5 be retained.

FAC-014-3, Requirement 8

The IRC SRC notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC0-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a. Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 may fail to correlate this information with CIP-002-5.1a, particularly as FAC-014-3 is not directly applicable to Generator Owners.

FAC-014-3, Measurement 3

The byproduct of removing "in accordance with its Reliability Coordinator's SOL methodology" to align with Requirement 3 language, introduces an inconsistency with similar FAC-014-3 language around each of its other Requirements and Measures and which is not justified by the Rationale which effectively makes it an option to include or not include the language within an RC's SOL methodology.

Doing so effectively allows for a TOP to provide their SOLs to the RC in any timeframe of their choosing, so long as they are provided. While the SDT Rationale points to potential duplicity or alignment with that of IRO-010-2 and thus the need for flexibility through the removal of

"in accordance with its Reliability Coordinator's SOL methodology", IRO-010-2 makes no direct reference to System Operating Limits. As such, the IRC SRC believes "in accordance with its Reliability Coordinator's methodology" to be appended to both R3 and M3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs). Likewise, R8 is in response to the same FERC directive. It is important to note that, without the proposals in Requirement R5, Part 5.6 & R8, there is no requirement for this type of information to be sent to the appropriate owners. Therefore, this is a reliability enhancement as it relates to this communication. The SDT is also adding clarity to the appropriate time horizons in Requirement R5, Part 5.6 with an updated posting of the standard. The concern with temporary conditions that lead to IROL establishment is well taken and the SDT agrees that temporary IROL conditions are not the appropriate trigger for TO & GO consideration pursuant to CIP-002-5.1a. However, this ambiguity exists today due to the wording in criteria 2.6 of the CIP standard that references specific facilities, identified by the RC (or planning entities) that are critical to the derivation of an IROL. The proposed Requirement R5, Part 5.6 does not change this reality. The SDT is not currently pursuing changes to the CIP standard as these efforts failed in the past when combined with the efforts of an ongoing CIP SDT. It is this SDT's opinion that CIP modifications would be best served by another drafting team, with an appropriate SAR, that can address all issues with the current criteria, some of which are not related to Project 2015-09.	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

1. Does this mean PC/TPs need to have "adverse impact" criteria in their Annual Assessment or does this return to the concept of any failure to meet TPL-001-4/5 System performance requirements of Table 1? As an alternative to all of this confusion, why not simply mirror the concept and clear language in Requirement R7: Requirement R8 - Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities identified as part of a Corrective Action Plan(s) developed to address any that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The wording referenced in the comment is pulling from the IROL definition and not the (similar) Adverse Reliability Impact definition. It is not clear what confusion the comment is referencing.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with the addition of requirement R5.6 as well as the revisions to measure M3. While the revised wording in requirement R8 is an improvement to the the previous posting, Southern Company believes that this requirement could result in burdensome communication even if there isn't any identified issues per the Planning Assessment to communicate. As such, Southern Company recommends the addition of the following sentence at the end of Requirement R8: *"Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication".*	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is the opinion of the SDT that the current wording of R8 clearly specifies the specific Facilities that are applicable. Additional clarity is being added to the rationale as well.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
We endorse the comments provided by AEP on 11/24/2020.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Entergy supports MISO's comments.	
Likes 0	

Dislikes 0	
Response	
Refer to response to referenced comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Jamie Johnson - California ISO - 2	
Answer	No
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	

Response	
Refer to response to referenced comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
If the application of Part 5.6 is intended to include three latter time horizons (Operations Planning, Same-day Operations and Real-Time Operations), AEPC believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard. A common language has been utilized to revise R8 which includes the language: “that adversely impact the reliability of the BES”. This language does not detail what is considered “adverse impact,” and therefore introduces inconsistencies among the industry. AEPC also signed on to ACES comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs). The wording in R8 mirrors the definition of IROL since the SDT is replacing references to planning IROLs as they will no longer exist with the retirement of FAC-010. Therefore, the wording in R8 should be interpreted consistently with this intent.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	

Answer	No
Document Name	
Comment	
Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

MPC agrees with and supports the MRO NERC Standards Review Forums comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The addition of the term ‘critical’ to R5.6 makes this revision difficult to support and impossible to ensure compliance. ‘Critical’ is not a defined term in the NERC Glossary - consider removing the term 'critical' or adding term to the NERC Glossary. The term critical was also inserted into R 5.2.4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. “Critical to the derivation of an IROL…” is used commonly in the body of NERC standards. The use in Requirement R5, Part 5.6 is consistent with this practice and would be interpreted/enforced consistently.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

I'm supporting MRO NSRF comments:

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to “at least once every 12 months,” FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to “at least once every 12 months” and Same-day Operations and Real-Time Operations be stricken from th applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.

Likes 0	
Dislikes 0	

Response

Refer to response to MRO NSRF comments

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

FAC-014-3, Part 5.6

The MRO NSRF notes that FAC-014, Part 5.6 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies. If the application of Part 5.6 is intended to include: Operations Planning, ***Same-day Operations and Real-Time Operations (with emphasis on the latter time horizons)***, the MRO NSRF believes that an FAC standard is not the best fit for this requirement and recommends this be relocated to an IRO standard.

If, however, the intent is to limit the time horizon to Operations Planning as indicated in Parts 5.1, 5.2 and 5.4 (tied to Part 5.2), which are limited in their application to "at least once every 12 months," FAC-014 may be the best fit location. If this is the case, the MRO NSRF recommends Part 5.6 be clarified to "at least once every 12 months" and Same-day Operations and Real-Time Operations be stricken from the applicable Time Horizons for Requirement R5 as illustrated below:

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.

Finally, if the deriviation of an IROL and its associated critical contingencies is considered temporary, there is no language in Part 5.6 of the standard that limits when and if CIP-002-5.1a must be applied to these facilities. The MRO NSRF recommends the SDT address this as part of this project as this has the potential to trigger a new Medium Impact Rating for an entity.

Regardless of location, the Guidelines and Technical Basis for CIP-002-5.1a will need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28).

FAC-014-3, Requirement 8

The MRO NSRF notes that FAC-014, R8 modifies and expands the existing FAC-014-2, requirements R5.1.1 and R5.1.3, to require Planning Coordinators and Transmission Planners provide Transmission Owners and Generator Owners with a list of their Facilities that comprise planning event Contingencies that would cause instability, Cascading or uncontrolled separation that adversely impact BES reliability as identified in its Planning Assessment. Similar to what is noted above for Part 5.6 , the Guidelines and Technical Basis for CIP-002-5.1a will

need to be updated to reflect and align with these changes (*see* references cited for Criterion 2.6 at the bottom of page 25 and page 28). Without this linkage, Generator Owners receiving information pursuant to FAC-014-3, Requirement 8 for the first time may fail to make the correlation to CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.The concern with temporary conditions that lead to IROL establishment is well taken and the SDT agrees that temporary IROL conditions are not the appropriate trigger for TO & GO consideration pursuant to CIP-002-5.1a. However, this ambiguity exists today due to the wording in criteria 2.6 of the CIP standard that references specific facilities, identified by the RC (or planning entities) that are critical to the derivation of an IROL. The proposed Requirement R5, Part 5.6 does not change this reality. The SDT is not currently pursuing changes to the CIP standard as these efforts failed in the past when combined with the efforts of an ongoing CIP SDT. It is this SDT's opinion that CIP modifications would be best served by another drafting team, with an appropriate SAR, that can address all issues with the current criteria, some of which are not related to Project 2015-09. Likewise, R8 is in response to the same FERC directive. It is important to note that, without the proposals in Requirement R5, Part 5.6 & R8, there is no requirement for this type of information to be sent to the appropriate owners. Therefore, this is a reliability enhancement as it relates to this communication. The SDT is also adding clarity to the appropriate time horizons in Requirement R5, Part 5.6 with an updated posting of the standard. The SDT is in agreement with the concern on the time horizons related to R5 and is modifying the standard in response.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	No
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	

Dislikes 0	
Response	
Refer to response to MRO NSRF comments	
Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Support the MRO-NSRF comments for R5.6 and M3. Recommend removing Req 8 or addressing the issue directly in CIP 002 or FAC 003. It is unclear how TO's and GO's would use this information as presented otherwise. For FAC-003, with the retirement of FAC-010-3 the PC is not resposible for identifying IROLs, and the language for '**4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.' should be changed to denote the RC. For CIP-002 '**2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.' the reference to PC should be removed.	
Likes 0	
Dislikes 0	
Response	
Refer to response to MRO NSRF comments	

The referenced CIP and FAC standards do not apply to the PC or TP as applicable functional entities. Therefore, the requirement to communicate planning information should be included in a standard applicable to planning entities.

Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State does not believe the revisions provide clear instruction. R5.6 language could be improved within the context of IROL development. 'Critical' to the derivation of an IROL is ambiguous and requires further clarification to ensure uniform interpretation and implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. "Critical to the derivation of an IROL…" is used commonly in the body of NERC standards. The use in Requirement R5, Part 5.6 is consistent with this practice and would be interpreted/enforced consistently.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is supportive of R5.6 as the proposed requirement clearly aligns and supports criteria outlined in CIP-002 and CIP-014. This requirement should remove any previous ambiguities that may have occurred in identifying facilities that are critical to the derivation of an IROL and its associated contingencies. AEP is also supportive of R8 as proposed as this will ensure GO's and TO's receive information for Facilities within their systems that could lead to instability/cascading and would create a more clear line of sight for those entities to take action on identified facilities accordingly to reduce potential risk of future instability/cascading. It should be noted however, the Corrective Action Plan and critical facility reports	

proposed within R7 and R8 are direct outcomes of TPL-001-4 requirements and should instead be included in that standard, if in any at all. There is no benefit having requirements pertaining to the reporting of planning studies scattered across different families of standards. AEP would like to make a suggestion and encouragement regarding how the standards drafting team provides redlined documents for industry review. While redlined documents using the previously proposed revision as a baseline do provide a very beneficial way for the reader to identify only the most-recently proposed changes, we believe that they cannot be the only redlined document provided during these comment and balloting periods. These particular redlines are simply a "delta" between the current and previous draft revision and do NOT show all the proposed additions and deletions that have been retained-to-date. This could result in the reader misunderstanding or misinterpreting the content in the draft. For example, text shown in black could be a) text currently included in the version under enforcement or b) new text that was proposed in a previous comment period but "no longer considered new text" in the current comment period. In addition, text shown as deleted could be a) text that has been newly proposed for deletion in the current comment period or b) text that was proposed for addition in a previous comment period draft but then later struck from consideration in a latter comment period. As a result, when multiple revisions are proposed over time, the reader would have to review each and every draft proposed to date and somehow determine for themselves all the changes retained to date. A balloter is not voting on only the most recently proposed changes, they are voting on all the proposed changes that have been retained-to-date. As a result, we recommend drafts showing only most recent changes also be accompanied by an additional redlined document which shows *all the proposed revisions retained to date*, and using the version under enforcement as a baseline.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The inclusion of R7 & R8 in the TPL-001 standard was investigated by the SDT and was ultimately not an option that was available to us. Future edits of the TPL-001 standard may take into account moving these requirements but that will occur under another SAR. The suggestions on the redline creation would be under the purview of NERC. The SDT does not control the methodology of the redline document creation.	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 1	Truong Le, N/A, Le Truong
Dislikes 0	
Response	
Refer to response to referenced comments.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
OPG support NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees that the addition of Requirement R5, part 5.6 enhances and clarifies the obligations of the RC under requirement R5. This change also supports GO and TO CIP compliance activities for CIP-002 and/or CIP-014. However, the reference within the FAC-014-3 Technical Rationale, on the top of page 6, incorrectly references "4.1.1.4 in CIP-014." This reference should be 4.1.1.3 (see below).

Excerpt from FAC-014-3 Technical Rationale, Page 6 (Rationale R5)

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and/or **4.1.1.4 in CIP-014**. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC.

CIP-014-2

Applicability Section 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner **as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies**. 4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements. EEI supports the modification to Measure M3. EEI supports the changes made to Requirement R8, which address our earlier concerns and provides clear requirements for Planning Coordinators and Transmission Planners that define what they must communicate to impacted TOs and GOs whenever planned contingency events indicate that instability, Cascading and uncontrolled separation would occur resulting in negative impacts to BES reliability in the Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will pursue corrections to the rationale to correct the CIP criteria reference.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	
Dislikes 0	

Response	
Refer to response to referenced comments.	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We agree with the revisions, however, please consider revising and renumbering the R5.2 sub-requirements as follows: 5.2.1 The value of the stability limit or IROL; 5.2.2 The associated IROL Tv for any IROL;	

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL and the associated Contingeny(ies); 5.2.4 A description of system conditions associated with the stability limit or IROL; and 5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT notes this comment. Ultimately, the change in numbering was deemed non-substantive and would require a significant number of documents to be re-balloted. Therefore, the SDT chose to leave the numbering as is in the current posting.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI). Submitted on behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	Yes
Document Name	
Comment	

Requirement R5.6 does not reference any schedule or frequency. Reclamation recommends adding a required communication cycle to align with the language in Requirement R5.2, to ensure that GOs and TOs have access to updated information, and to provide the RCs with greater confidence in responses received from entities that must document the lack of Facilities critical to the derivation of an IROL for CIP-002. Reclamation recommends the following language:

Change from:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies.

To:

Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies **at least once every twelve calendar months**.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The periodicity of communication is being addressed in an updated posting of the standard.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	Yes
Document Name	
Comment	

In regards to requirement R8, BC Hydro requests that the drafting team confirm if it the intent was to include the extreme events (as referenced on page 11 in Table 1 of TPL-001-4) when determining the “list of Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon”?

Including the extreme events for consideration under the FAC-014-3 R8 appears to be an expansion of the current requirement R6 of FAC-014-2, which only references multiple contingencies per TPL-003 (not including extreme events, which were covered in TPL-004 System Performance under Extreme Events prior to TPL-001-4 becoming effective).

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The intent is for planning events to be the primary applicability of R8. Inclusion of select extreme events in the applicability is not precluded by this requirement but should be the determination of PC/TP based on their expertise or other applicable factors specific to their respective areas or coordination practices with owners.

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

FAC-014-3, R5.6

FAC-014-3, Part 5.6 modifies and expands the existing FAC-014-2 to require Reliability Coordinators provide Transmission Owners and Generator Owners with a list of their Facilities identified as critical to the derivation of an IROL and its associated contingencies.

Facilities identified as critical to the derivation of an IROL and its associated contingencies is a criterion for applying a Medium Impact Rating under CIP-002-5.1a. The proposed requirement R5.6 is redundant and we suggest that there is no reliability need to expand FAC-014-2 with the proposed R5.6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed Requirement R5, Part 5.6 is in response to a FERC directive (Order 777) to include a communication path for IROL information to the owning entities as part of this project. It was addressed as a subpart of R5, which addresses RC communication requirements of SOLs (including IROLs)	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS does not have comments for the revised measurement M3 of FAC-014-3. AZPS does not have comments for the the added requirement 5.6 as it currently does not impact AZPS however may have potential impact in the future. AZPS does not have comments for R8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	

Ed Hanson - Pacific Gas and Electric Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Weaver - Tallahassee Electric (City of Tallahassee, FL) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamalet Mackey - Pamalet Mackey On Behalf of: Ed Hanson, Pacific Gas and Electric Company, 1, 3, 5; Sandra Ellis, Pacific Gas and Electric Company, 1, 3, 5; - Pamalet Mackey	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tammy Porter - Tammy Porter On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tammy Porter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Ellis - Pacific Gas and Electric Company - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Nurul Abser - NB Power Corporation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Richard Brooks - Reliable Energy Analytics LLC - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you	
Robert Hirchak - Cleco Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned there is no timeline for the provision of the list of Facilities in the new Requirement R5.6. Texas RE suggests being consistent with Requirements 5.1 and 5.2 which specify "at least once every twelve calendar months." Texas RE also recommends capitalizing "Contingency(ies)" since it is defined in the NERC Glossary.

For Requirement R8, Texas RE inquires as to whether it is intended that all lines "that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES" that are communicated to the GO or TO under R8 would be applicable to FAC-003-5. FAC-003-5 section 4.2.2 states "Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event."

Texas RE reads this language to require all overhead transmission lines operated below 200 kV communicated by Planning Coordinators and Transmission Planners comprising planning event Contingencies causing instability, Cascading, or uncontrolled separate to remain subject to the FAC-003-5 vegetation management requirements. However, Texas RE is concerned that, for a planning event that involves multiple Contingencies (P3 – P7), the standard could be read to exclude single Facilities associated with the event by virtue of the fact that the loss of the individual Facility does not result, by itself, in instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System. Texas RE believes that such a reading could result in a reliability gap if individual Facilities under 200 kV that contribute to instability, Cascading, or uncontrolled separation in planning studies are arguably not included within the scope of FAC-003-5. Accordingly, Texas RE requests that the SDT clarify that it did not intend to exclude such Facilities from the scope of the FAC-003-5 vegetation management requirements.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The periodicity of communication for Requirement R5, Part 5.6 is being addressed in an updated posting of the standard. The modifications to FAC-014 and related modifications to FAC-003 are replacing the reference to planning IROLs with more appropriate language. The language used incorporates the definition of IROL so the intent is to not change the facilities that are applicable to FAC-003, but rather to correct the reference to those Facilities and provide a mechanism for this information to flow from planners to owners. Additionally, the SDT did not exclude any planning events from being applicable to R7 and R8 so facilities associated with P3 – P7 events should not be excluded with the new wording in the proposed standard revisions.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	

Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Refer to response to referenced comments.	
Colleen Campbell - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you	

3. If you have any other comments regarding FAC-014-3 and the Implementation Plan that you haven't already provided, please provide them here.	
Michael Whitney - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
See prior NCPA and John Allen City Utilities prior balloting comments.	
Likes 0	
Dislikes 0	
Response	
See response to City Utilities comments.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
See prior John allen and John Allen City Utilities prior balloting comments	
Likes 0	
Dislikes 0	
Response	
See response to City Utilities comments.	

Robert Hirchak - Cleco Corporation - 6	
Answer	
Document Name	
Comment	
No other comments	
Likes 0	
Dislikes 0	
Response	
John Allen - City Utilities of Springfield, Missouri - 4	
Answer	
Document Name	
Comment	
City Utilities of Springfield appreciates the 2015-09 team's consideration of our previous comments. We understand the desire to complete this five year old project, but respectfully disagree that additional changes are not necessary. We believe that current projects should not continue creating requirements that are either unclear, redundant or out of place in the body of Reliability Standards. This is contrary to all the efforts industry is putting forward in the Standards Efficiency Review project. Therefore, City Utilities stands firm on our previous comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team understands the concerns and the responses made to the previous set of comments remains valid.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP is concerned by the usage and meaning of "stability criteria" within R6, and request that the SDT provide clarity regarding the exact meaning of this phrase. Does it mean the acceptable power swing damping level and transient voltage dip and recovery durations? Does it mean the bare necessity for the system to remain stable? Does it mean the P1-P7 contingency definitions used in studies to evaluate stability? Does it mean the stability SOLs themselves? Uncertainty regarding the exact meaning of this phrase leads us to offer the following feedback…

If "stability criteria" means stability SOLs themselves, then the following feedback paragraph applies. The RC must deal with real-time outages, often simultaneous multiple outages that may result in more restrictive stability operating limits than are considered in planning studies. Example: the RC secures system against P4 stuck CB events during other real-time outages. In planning, prior outages are not required to be simulated by the TPL standard for P4 events, nor have they been regarded as necessary for P4 event planning purposes in the past. Depending on a RC's SOL methodology, the proposed R6 may impose more restrictive limits on planning studies, and for this reason, might result in corrective action plans and expense that would not have been identified in the past. R6 may also result in complication and confusion between planning and operations because it may never be clear out of the numerous outage conditions encountered by operations in any day, season, or year, which of these must be considered in planning studies under the proposed R6. It is also quite likely that particular combinations of outages will never appear again, rendering planning studies that are forced to recognize SOLs resulting from such outage combinations as "more limiting stability criteria" not very relevant.

If "stability criteria" means the acceptable power swing damping level and transient voltage dip and recovery durations, or the bare necessity for the system to remain stable, or the P1-P7 contingency definitions used in studies to evaluate stability then the following feedback paragraph applies. The RCs, PCs, and TPs most probably already have (and in our experience *do* have) coordinated power swing damping criteria and would have consistent transient voltage criteria should that ever be applied in operations. There is no valid reason to require this in FAC-014. The performance measure requiring system stability to be maintained is the same by definition in both operations and planning. Contingency event definitions are also the same between operations and planning. If there are no other stability criteria to be coordinated between RC and PC/TP, the proposed R6 may be useless for stability planning purposes and will only cause needless administrative paperwork.

In addition, real-time generation redispatch is often assumed in planning studies to resolve instability and it is not always considered a Corrective Action Plan. Real-time generation redispatch may be particularly relevant to P6 scenarios as “system adjustments” as distinguished from “corrective action plans.” Thus, real-time redispatch may either result in no corrective action plan because it is not considered a corrective action plan (nullifying R7) or, as a system adjustment, will result in no planning event instability, cascading, or uncontrolled separation (nullifying R8). The reliability benefit of the proposed R7 and R8 may be nullified if generation redispatch is used to resolve instability.

AEP recommends removal of “stability criteria” from the proposed R6 and transfer of the proposed R7 and R8 over to a TPL-001 Standards Drafting Team. While well intentioned, we believe the Project 2015-09 Standards Drafting Team is unintentionally encroaching on the TPL domain by proposing R7 and R8 be placed within FAC-014. These requirements are best served if drafted and reviewed from a Transmission Planner perspective which can properly evaluate their necessity in view of the potential for nullification by possible reliance on operational actions and system adjustments not considered corrective action plans.

While we obviously do not yet know the answers to the “stability criteria” question we have posed above, we would like to propose the following revisions to R6 which we believe may provide clarity and minimize compliance burden...

Each Planning Coordinator and each Transmission Planner shall ~~implement a documented process to~~ ~~use~~ *incorporate* Facility Ratings, System steady-state voltage limits and stability limits ~~criteria~~ in its Planning Assessment of Near Term Transmission Planning Horizon ~~that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator’s SOL methodology~~ *as identified in Requirement 5.1 and 5.2.*

• The Planning Coordinator may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may *also* use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

In the event that the formatting used for our suggested revisions to R6 (showing both our deleted and added text) are not retained by the SBS system, we provide it here again, showing only the retained and added text in a "clean format."

Each Planning Coordinator and each Transmission Planner shall incorporate Facility Ratings, System steady-state voltage limits and stability limits in its Planning Assessment of Near Term Transmission Planning Horizon as identified in Requirement 5.1 and 5.2.

• The Planning Coordinator may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may also use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

The compliance burden is minimized by simply requiring the PC/TP to incorporate RC ratings and limits in TPL assessments instead of requiring yet another process document for what should be a straightforward comparison check. Emphasizing Requirements R5.1 and R5.2

in R6 clarifies the responsibility of the PC/TP. R5.1 and R5.2 provide the PC/TP specific SOL/IROL/stability limits from the RC that can be incorporated into Planning Assessments. Only referencing an RC's SOL methodology as originally proposed in R6 could lead to much interpretation by the PC/TP since they are only methodology documents. In addition, from a stability perspective, requiring the PC/TP to evaluate specific stability events as identified by the RC in R5.1/R5.2 provides a finite set of events to be considered for the Planning Assessment. It is possible that some of the stability limits from the RC will not satisfy Planning Assessment criteria, but using R5.1/R5.2 as the point of reference provides structure to the Planning Assessment process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The term "stability criterion" is common language that is used or synonymous with language elsewhere in the standards, most notably in TPL-001-4. The SDT feels it is sufficient to describe the intent of the requirement. The term "stability criterion" refers to the criterion used to establish stability SOLs and not the SOLs themselves. Which seems to be in line with latter understanding presented. However, there is a need to highlight it within the FAC-014 standard for the purpose of clarity in ensuring Planning criterion is more stringent than Ops criterion for stability as no such requirement exists today and not all Planning and Operating entities are so closely aligned. Regarding the comments to R7 and R8, future consideration will be given to moving R6, R7 and R8 into TPL-001. The suggestion to alleviate perceived "compliance burden" does add structure, but does not fit for entities that do not establish limits within their Planning functions. It does not negate the need for process to use Facility Ratings, System steady-state voltage limits and stability criteria in the Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology,.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Glen Allegranza - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
no comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
The current effective standard FAC-014-2 version, Requirement 5.1.3 states “The associated Contingency(ies)”. The proposed FAC-014-3, Requirement 5.2.4, states “The associated critical Contingency(ies).” What distinguishes a “critical” contingency(ies)?	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response given to Dominion Energy.	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
No Additional comments	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
R6: Techincal rational seems inconsistent with how the language as written could be read. Requirement does give the RC authority over the PC in it sets a performance requirement for the PC to meet outside of the TPL standard. It seems to pre-suppose that the PC's criteria and the Facility Ratings it uses may be suspect. Suggest the SDT draft language for the RC to simply submit its SOL methodology and ratings and perhaps more importantly the basis to the PC for review and comment. The PC can then determine what is applicable for its planning assessment.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The technical rational did intend to presuppose the PC's criteria may be suspect. The suggestion is welcomed. However, there remains a need to document a process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology, to support an operable real-time system.	
Jerry Horner - Basin Electric Power Cooperative - 6	
Answer	
Document Name	
Comment	
Basin Electric supports the MRO NSRF comments. Jerry Horner	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF comments.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

{C}· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

{C}· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. It is unclear what is recommended in the first paragraph of the comments (if anything) as the second paragraph starts off with, "The MRO NSRF also recommends…"

The terms "system steady-state voltage" and "stability criterion" use common language that is used or synonymous with language elsewhere in the standards, most notably in TPL-001-4. The SDT feels they are sufficient to describe the intent of the requirement.

Regarding the comments to R7 and R8, future consideration will be given to moving R6, R7 and R8 into TPL-001.

Thank you for your comment regarding Part 6.4. The SDT agrees in principle with the commenter. FAC-011-4 Part 6.4 refers to requirements that should be in the RC methodology. Through those requirements, it guides the Operating Plans developed by the RC and TOP in their Real-time Assessment and the Operational Planning Analysis, which would be the "planned" actions. The response by an operator to an event in Real-time monitoring would be based on those Operating Plans but part 6.4 would not directly apply to those real time actions. The RC's methodology can provide further clarity when addressing part 6.4.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	

R6:

The SDT agreed with BPA's previous comments to the proposed revisions.The SDT noted that the Technical Rationale would be revised to ensure this clarity was captured and explained. BPA's concern is that the Technical Rationale is apart from the Standard and would likely not be used by the auditors. BPA believes this language needs to be explicitly stated in the Standard.

Additionally, after further review of the SDT's proposed language, BPA does not agree with using the term "criteria" before Facility Ratings.

SDT Proposed Language for R6:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

BPA recommends the following edits to add clarity to the STD's proposed R6 revisions. BPA also believes '***system voltage limits'*** should not be capitalized, as it is not defined in the NERC Glossary of Terms. (Bold, italic text for additions):

R6. Each Planning Coordinator and each Transmission Planner shall ***ensure that Facility Ratings and system voltage limits*** *used* in its Planning Assessment of the Near Term Transmission Planning Horizon are equally limiting or more limiting than the ***Facility Ratings and system voltage limits provided by the TOP to its RC in accordance with*** its Reliability Coordinator's SOL methodology. ***In addition, each Planning Coordinator and each Transmission Planner shall ensure that criteria developed and documented for stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for stability specified in its respective Reliability Coordinator's SOL methodology.*** *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

BPA has no suggested changes to the R6 bullets below.

• The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.

• The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

R7:

BPA appreciates the SDT incorporating the language *"…that adversely impacts the reliability of the Bulk Electric System…"* into the modified R8. BPA's other comments were in response to Corrective Action Plans. BPA does not believe that the addition of language in R8 satisfies our concerns with R7. BPA believes R8 is a subset of R7.4 where R7.4 is related to the contingency event, and R8 is related to the facilities that comprise the contingency event.

BPA believes it should only be required to communicate/report information for Corrective Action Plans to impacted Transmission Operators and Reliability Coordinators that adversely impact the reliability of the Bulk Electric System. Corrective Action Plans for local issues within a TP's system that do not impact the reliability of the Bulk Electric System should not have to be communicated/reported. As R7 is currently

written, all Corrective Action Plans would need to be communicated/reported. This is consistent with the SDT's response to comments from earlier postings. BPA suggests modifying R7 with the following language below (bold, italic text added) to avoid the burden of communicating/reporting on local issue Corrective Action Plans. By making this change, enitities will only be required to report Corrective Action Plans that affect the larger BES. R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon ***that adversely impacts the reliability of the Bulk Electric System*** to each impacted transmission Operator and Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Regarding R6, the suggestion is welcomed; however, the SDT feels there is a need to document a process and the word "ensure" does not given enough description of how to execute a requirement. "System Voltage Limits" was a defined term introduced in recently passed balloting associated with proposed FAC-011-4. The suggestion for R7 is appreciated; however, CAPs are sufficiently described in TPL-001-4 such that this additional language is not required.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

Draft 3 of this standard added requirements for the quality of transmission assessments performed per TPL-001. In particular, R6 calls for Near Term Transmission Planning to use Facility Ratings and Voltage Limits that are equally or more limiting than in the Reliability Coordinator's SOL methodology. Also, R7 calls for Planning Coordinators and Transmission Planners to annually communicate selected results of the Near-Term Transmission Planning results with Transmission Operators and Teliability Coordinators. Ideally, requirements R6 and R7 need to be in TPL-001 instead of FAC-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Future consideration will be given to moving R6, R7 and R8 into TPL-001.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
FAC-014-3, Requirement R6 The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."	

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, “System Voltage Limits” (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as “System steady state voltage limits” as well as “System Voltage Limits”. The MRO NSRF recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, “stability limits”, and “stability performance criteria” (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as “stability criteria” or just “stability”. The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator’s SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen

TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time. **FAC-011-4, Part 6.4** Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, “planned manual load shedding is acceptable only after all other available System adjustments have been made,” only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. ‘Operations Planning,’ and the descriptor of “*planned*“ manual load shedding.

Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	

Dominion Energy suggests modifying the term “an instability”, as contained in Requirement R4, to “an identified instability”. This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

Dominion Energy requests the SDT clarify the addition of the word “critical” to describe Contingency(ies)” noting that “critical Contingency(ies)” is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For Dominion Energy to support this change, the term “critical Contingency(ies)” need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term “critical Contingency(ies)”.

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Dominion Energy disagrees with the inclusion of “as established in FAC-011-4” within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all

references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement R4 has been updated as per your suggestion. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. The FAC-014-3 VSLs have been revised as per your comments.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
FAC-014-3, Requirement R6 The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology."	

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The MRO NSRF recommends that consistent terminology be used across these standards.

· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that

the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time. **FAC-011-4, Part 6.4** Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, "planned manual load shedding is acceptable only after all other available System adjustments have been made," only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments filed by the MRO NERC Standards Review Forum (NSRF) for this question.	
Likes 0	

Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the IRC comments.	

Neil Shockey - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO supports comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) and MRO NERC Standards Review Forum (MRO NSRF).	
Likes 0	
Dislikes 0	
Response	
Please see the response to the IRC and MRO NSRF comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	

Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
Oliver Burke - Entergy - Entergy Services, Inc. - 1	
Answer	
Document Name	
Comment	
N/A - Entergy supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MISO comments.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

NIPSCO endorses the other comments on R6, R7, and R8 provided by AEP on 11/24/2020. And reiterates our prior NIPSCO comments provided 7/31/2020.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the AEP comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE has the following comments, noted by section. Implementation Plan – Effective Date sectionn • There is a missing delimiter (“) around System Operating Limit (shows *“System Voltage Limit” and System Operating Limit”* but should be *“System Voltage Limit” and “System Operating Limit”*). Implementation Plan - Prior Implementation Plans section: • PRC-005-3 is referenced and it seems that it should reference PRC-005-6. • Texas RE recommends noting that there have been changes to the language of FAC-003-5 to include the TP as an entity that can designate a line and also uses the language “identified the line in Applicability under 4.2” instead of “designates the line as being an element of an IROL”. Texas RE agrees this change should not significantly modify the application of the implementation plan.	

- For FAC-003-5 "Newly Designated Lines" - There seems to be some ambiguity about what happens to the lines newly designated under FAC-003-4 Applicability Section 4.2 language in the last year of applicability for FAC-003-4. Do those lines receive an additional year of non-applicability because the new version of the Standard is being applied?
- For PRC-002-3, "TO" and "RC" should be spelled out to be consistent.

Implementation Plan - Additional Provisions section:

- For FAC-014-3 Requirement R6, Texas RE recommends a clear date by which the Planning Assessment must reflect the implementation of Requirement R6 (e.g 24 calendar months after effective date). The language "when it begins its next cycle for conducting the studies to support its Planning Assessment" for R6 is not measureable and may lead to inconsistent understanding and application.

Additional FAC-014-3 Comments:

- Texas RE noticed the SDT added the word "critical" in in FAC-014-3 5.2.4. Texas RE is concerned that since there is no criteria or definition of the word critical, inconsistencies could arise between entities regarding the meaning of "critical" which, in turn, could lead to perceived inconsistencies in monitoring. Texas RE recommends drafting clear criteria to determine "critical" to ensure reliability. While it was added to accommodate the 5.6 language addition there is no clear meaning of the word or intent. When reviewed in audit space there will be a need to understand what "critical" means to an entity and how they derived, and applied, the thought process.
- In Requirement R6, there should be a hyphen in "Near Term". This is consistent with the NERC Glossary Term.

Texas RE continues to be concerned with the following:

- The asterisk on FAC-003 Table 2 appears to be inconsistent with FAC-014. The asterisk is applicable only "if PC has determined such per FAC-014." FAC-014 includes both of the PC and TP in Requirements R6-R8. The footnote as written excludes the TP so it is unclear whether TP Facilities, determined per FAC-014 R8, are subject to vegetation management. This could leave a gap in the

reliable operations of the grid if the list of Facilities derived by the PC and TP are different. Texas RE recommends adding "and TP" to the footnote in FAC-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Corrections to references and characters are appreciated and have been addressed. The implementation date for FAC-014-3 R6 has been clarified. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. Your comments in relation to FAC-003 have been noted for future consideration.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
For Requirements R5 and R8, Reclamation recommends that the SDT consider adding an annual notice to the TOs and GOs that do not own impacted Facilities. This would increase transparency and provide direct evidence of the lack of impact.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. While this notice would be a nice gesture, the SDT feels that as part of a Requirement, it would not amount to a material benefit in light of the effort.	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company disagrees with the revision to R4. The revision creates unnecessary confusion compared to the original language, seeming to imply that each Reliability Coordinator shall establish stability limits only after an instability event that impacts adjacent Reliability Coordinator Areas has occurred. As such, if the revision is to remain, the following revision is suggested to clarify that this is a proactive coordination, not reactive:

Revise from “an instability” to “an *identified* instability”.

Southern Company disagrees with Requirement R5.2.2, as the modifications to the requirement create unnecessary ambiguity. Specifically, Southern Company disagrees with the inclusion of the word “derivation” in R5.2.2 as there can be a significant number of Facilities across the Interconnections needed to accurately model and simulate a stability event and therefore are critical to the “derivation” of a stability limit. It is suggested instead that “derivation” be defined or replaced with “establishment” to better clarify those Facilities that should be identified.

While Southern Company supports the removal of FAC-015-1, retirement of FAC-010, and inclusion of the requirements as contemplated in R6 through R8 of the proposed FAC-014-3, these requirements are best located in TPL-001, not FAC-014. The proposed FAC-014-3 “Establish and Communicate System Operating Limits” should cover the responsibilities related to SOLs, which no longer apply to near/long-term planning horizons. The communication of planning information by the TP and PCs should be appropriately housed in the TPL standard family to prevent confusion and cross pollination of standards.

FAC – 014 R7 and R8 could result in burdensome communication even if there isn’t any identified issues per the Planning Assessment to communicate. As such, we suggest the following language modifications:

- Modify the last sentence of FAC-014 R7 from “This communication shall include:” to “This communication, which is required if any information in Part 7.1 – Part7.5 is identified, shall include:”.
- Add another sentence at the end of R8, as also suggested in Comment Form Question 2 above: “Planning Coordinators and Transmission Planners that do not identify any Facilities are not required to perform the annual communication”.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Requirement R4 has been updated as per your suggestion.

The term "derivation" is used throughout the standards especially pertaining to operating limits. The SDT believes the language proposed in requirement part 5.2.2 is clear.

The SDT considered the suggestion provided for R7 and R8; however, it's felt this type of clarity if required can be specified in PC/TP procedures in agreement with the RC/TOP or TO/GO, respectively. Future consideration will be given to moving R6, R7 and R8 into TPL-001.

Daniel Gacek - Exelon - 1

Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the Edison Electric Insititue (EEI).

Submitted on behalf of Exelon: Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	
Response	

Please see the response to the EEI comments.

sean erickson - Western Area Power Administration - 1

Answer	

Document Name	
Comment	
thank you	
Likes 0	
Dislikes 0	
Response	
You are welcome.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

FAC-014-3 Comments

Requirement 6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."

The IRC SRC agrees with previously provided comments from the IRC SRC that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on GOs and TOs. Additionally, from a Planning study perspective TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to comments submitted by the IRC SRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. The IRC SRC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

The IRC SRC also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The IRC SRC recommends that consistent terminology be used across these standards.
- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The IRC SRC recommends that consistent terminology be used across these standards.

Finally, the IRC SRC recommends that the following ***change*** be made to R6 to clarify the intent of the requirement:

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, ***System Voltage Limits*** and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the ***use of*** Facility Ratings, System Voltage Limits and stability ***criteria*** described in its respective Reliability Coordinator's SOL methodology.

Requirement 7

FAC-014-3, R7 is duplicative of existing NERC Standard IRO-017-1, R3 which obligates each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators. The IRC SRC recommended IRO-017-1, R3 be updated so that this type of request is located in a single requirement or standard. The SDT response to this request is that the IRO-17 standard deals with outage coordination (and not SOLs) that FAC-014 is the proper place for SOL transmittal and related information between entities. Additionally, the SDT acknowledges that they discussed at length the annual planning assessment created per TPL-001, and noted that the information described in FAC-014-3, R7 is not necessarily included explicitly in annual planning assessments, but is of great use to operating entities seeking to monitor and mitigate any potential instability. The IRC SRC disagrees as the information required in FAC-014 R7 is included in TPL-001 assessments. Requirement 2.7 of TPL-001 requires that the assessment identify the Corrective Action Plan for instances where the analysis indicates the inability to meet the performance requirements. Obligating the Planning Coordinator and Transmission Planner to only communicate Corrective Action Plans for instability issues falls short of information that would be important for Transmission Operators and Reliability Coordinators. As such, updated TPL-001 to provide the report in its entity to Transmission Operators and Reliability Coordinators provides a more holistic view of all Corrective Action Plans that may be forthcoming to the system. As such, the IRC SRC recommends that TPL-001 R8 be modified to specifically include Transmission Operators and Reliability Coordinators. **FAC-011-4** Finally, the IRC SRC would like the drafting team to confirm in a response to comments or the technical rational document that FAC-011-4, Part 6.4 only applies to addressing overloads that are observed in a planning or forecasted timeframe and Part 6.4 would not restrict the RC from taking actions in Real-time if the planned mitigating actions are ineffective or insufficient to address an impending IROL exceedance. This observation is made based on the reference to time horizon being identified as 'Operations Planning' and the use of *planned* manual load shedding	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The term "system steady-state voltage" is used in TPL-001-4 and is associated with the Planning Assessment as it is used in the proposed FAC-14-3 R6; therefore, the SDT feels it should not create confusion in regards to the intent of the requirement. In addition, the terms	

"stability" or "stability criteria" are used throughout the standards and the SDT does not feel that using them in the context set out in R6 creates confusion.

Regarding the comments pertaining to facility ratings, MOD-32 and R7 and R8, future consideration will be given to these requirements moving into other standards.

The comment regarding FAC-011-4 part 6.4 has been addressed in line with your request.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	

Please consider if revisions to section "C. Compliance" are necessary to update FAC-014-3 with the current NERC wording for the Compliance section. For example, "Compliance Enforcement Authority" could be abbreviated as CEA in the Compliance section.

RE: Violation Severity Levels, R1, Severe VSL: Please consider removing, "as established in FAC-011-4" since this reference appears to be unnecessary.

RE: Technical Rationale for Reliability Standard FAC-014-3, Rationale R5, part 5.6: Please consider correcting the reference to 4.1.1.4 in CIP-014 to read as 4.1.1.3 in CIP-014.

Requirement 6

The provided rationale document for Requirement 6 states, "The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System." The rationale document also states (following on from the earlier quote), "This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology." In consideration of the RC SOL methodology to be provided per the draft FAC-001-4, Requirement 2 states, "each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings."

NPCC RSC believes that several standards (such as FAC-008 and MOD-032) place the obligations of determining Facility Ratings on the GO and/or TO. Additionally, from a Planning study perspective, TPL-001-4 Requirement 1 obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

In its reply to the previous comments from the SRC IRC, the Standard Drafting Team (SDT) states that they understand the perception of redundancy of this requirement as compared to other NERC Standards, but industry and regulatory comments/inputs moved the SDT down the current path of including Facility Ratings as part of R6. Further, the SDT recognizes the facility owner's responsibility in providing Facility Ratings per FAC-008 and that this does not conflict with what is proposed in FAC-014. NPCC RSC recommends that by including the Facility Ratings requirement in other standards (such as MOD-032), increased benefit is seen across additional standards and not just the Planning Assessment of Near-Term Transmission Planning Horizon.

NPCC RSC also recommends the following additional changes to the language in the requirement:

{C}· FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady-state voltage limits" as well as "System Voltage Limits". We recommend that consistent terminology be used across these standards.

{C}· FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". We recommend that consistent terminology be used across these standards.

Finally, NPCC RSC recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. Those pertaining to the FAC-014-3 VSL and rationale have been addressed. The SDT believes the de-lineation between proposed FAC-014-3 regarding the use of the Facility ratings vs. the determination of the ratings themselves is clear in the requirement and rationale. Regarding the comments pertaining to facility ratings, MOD-32 and R7 and R8, future consideration will be given to these requirements moving into other standards The term "system steady-state voltage" is used in TPL-001-4 and is associated with the Planning Assessment as it is used in the proposed FAC-14-3 R6; therefore, the SDT feels it should not create confusion in regards to the intent of the requirement. In addition, the terms "stability" or "stability criteria" are used throughout the standards and the SDT does not feel that using them in the context set out in R6 creates confusion.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP RTO	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy incorporates by reference and supports the comments of Edison Electric Institute (EEI) in response to Question 3.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI commnets	
Likes 0	

Dislikes 0	
Response	
Please see the response to the EEI comments.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

NV Energy supports MRO NSRF's additional comments:

FAC-014-3, Requirement R6

The provided rationale document for Requirement 6 states, “The intent of Requirement 6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor to allow the PCs or TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System.” The rationale document also states (following on from the earlier quote), “This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC’s SOL methodology.”

From a Planning study perspective, TPL-001-4, Requirement 1, obligates PCs and TPs as part of their Planning Assessment of the Near Term Transmission Planning Horizon to use data consistent with what is provided in accordance with MOD-032.

The MRO NSRF also recommends the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, “System Voltage Limits” (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as “System steady state voltage limits” as well as “System Voltage Limits”. The MRO NSRF recommends that consistent terminology be used across these standards.

- FAC-011-4 uses the phrases, “stability limits”, and “stability performance criteria” (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as “stability criteria” or just “stability”. The MRO NSRF recommends that consistent terminology be used across these standards.

Finally, the MRO NSRF recommends that the following change be made to R6 to clarify the intent of the requirement:

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the use of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator’s SOL methodology.

FAC-014-3, Requirement 7

As proposed FAC-014-3, R7 is partially duplicative of existing requirements under IRO-017-1, R3 and TPL-001-4, R8 which obligate Planning Coordinators and Transmission Planners to provide Planning Assessments to impacted Reliability Coordinators and adjacent Planning Coordinators and Transmission Planners, respectively. The MRO NSRF requests the SDT update an existing requirement rather than introduce a new requirement so that this type of information is consolidated in a single location. That said, the MRO NSRF recognizes that the information referenced in FAC-014, R7 is not explicitly required under either of the aforementioned standards and the option to reopen TPL has been discussed at length by the SDT. As a decision has been made not to reopen TPL-001 at this time, the MRO NSRF requests TPL-001, R8 be expanded to include Transmission Operators and Reliability Coordinators when it is next reopened for modifications and FAC-014-3, R7 be retired at that time.

FAC-011-4, Part 6.4

Finally, the MRO NSRF requests the SDT confirm in a response to comments or in a Technical Rationale document that **FAC-011-4, Part 6.4**, “planned manual load shedding is acceptable only after all other available System adjustments have been made,” only applies to addressing overloads that are observed in a planning or forecasted timeframe and is not intended to address actual overloads in Real-time on the

system. This observation is made based on the Time Horizon for R6; i.e. 'Operations Planning,' and the descriptor of "*planned*" manual load shedding	
Likes 0	
Dislikes 0	
Response	
Please see the response to the MRO NSRF comments.	
Jose Avendano Mora - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the response to the EEI comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
None and thank you for the opportunity to comment.	
Likes 0	

Dislikes 0	
Response	
You are welcome.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI suggests modifying the term "an instability", as contained in Requirement R4, to "an identified instability". This proposed change makes Requirement R4 clear that the intent is for the RC to act on identified instability, not after an instability event has occurred.

EEI requests the SDT clarify the addition of the word "critical" to describe Contingency(ies)" noting that "critical Contingency(ies)" is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. For EEI to support this change, the term "critical Contingency(ies)" need to be clarified or removed.

Alternatively, the SDT could consider revising the supporting subparts of 5.2 (Requirement R5), as indicated below, as a possible solution to the use of the undefined term "critical Contingency(ies)".

5.2.1 The value of the stability limit or IROL;

5.2.2 The associated IROL Tv for any IROL;

5.2.3 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL **and the associated Contingency(ies)**;

5.2.4 A description of system conditions associated with the stability limit or IROL; and

5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

EEI disagrees with the inclusion of "as established in FAC-011-4" within the Severe VSL level within FAC-014-3, Requirement R1. Since requirements can be moved out of one Reliability Standard to another, modified, or retired, this creates a burden to ensure all references are identified when modifications are made. Each Reliability Standard should stand on its own and should not contain linkage to other Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Requirement R4 has been updated as per your suggestion. The term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear. The FAC-014-3 VSLs have been revised as per your comments.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG support NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to the NPCC comments.	
Ed Hanson - Pacific Gas and Electric Company - 5	

Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through December 7, 2020

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, December 7, 2020** for the following standard and implementation plan:

- FAC-014-3 – Establish and Communicate System Operating Limit
- Implementation Plan

Commenting and Balloting

Use the Standards Balloting and Commenting System (SBS) to submit comments. Contact Linda Jenkins regarding issues using the SBS. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, along with the non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 27 – December 7, 2020**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 4 ST
Voting Start Date: 11/27/2020 12:01:00 AM
Voting End Date: 12/7/2020 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 270
Total Ballot Pool: 326
Quorum: 82.82
Quorum Established Date: 12/7/2020 4:38:24 PM
Weighted Segment Value: 66.61

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	93	1	50	0.676	24	0.324	1	6	12
Segment: 2	8	0.8	3	0.3	5	0.5	0	0	0
Segment: 3	74	1	34	0.68	16	0.32	1	6	17
Segment: 4	15	1	7	0.636	4	0.364	0	1	3
Segment: 5	70	1	40	0.755	13	0.245	0	5	12
Segment: 6	54	1	28	0.683	13	0.317	1	4	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	7	0.6	5	0.5	1	0.1	0	0	1
Totals:	326	6.5	168	4.33	76	2.17	3	23	56

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
	Massachusetts Municipal Wholesale Electric				

5	Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Abstain	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
6	Westar Energy	Grant Wilkerson		None	N/A
3	Westar Energy	Bryan Taggart		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Negative	No Comment Submitted
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Abstain	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A

3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
7	Luminant Mining Company LLC	James Watson		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	Third-Party Comments

1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		None	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		None	N/A
5	Florida Municipal Power Agency	Chris Gowder		Negative	Third-Party Comments
6	Florida Municipal Power Agency	Richard Montgomery		Negative	No Comment Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
6	Muscatine Power and Water	Nick Burns		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
		Salvatore			

1	New York Power Authority	Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	No Comment Submitted
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
		Brian Evans-			

4	Utility Services, Inc.	Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Negative	Third-Party Comments
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	AEP	JT Kuehne		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments

					Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Negative	Third-Party Comments
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Mickey Bellard		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A

1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		None	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Great River Energy	Donna Stephenson		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
6	Omaha Public Power District	Joel Robles		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	Aaron Smith		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		None	N/A
1	Pacific Gas and Electric Company	Marco Rios		Affirmative	N/A
		Thomas			

1	Austin Energy	Standifur	Affirmative N/A
6	Evergy	Thomas ROBBEN	Affirmative N/A
1	Evergy	Allen Klassen	Affirmative N/A
3	Evergy	Marcus Moor	Affirmative N/A
5	Evergy	Derek Brown	Affirmative N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy	Affirmative N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative N/A

NERC Balloting Tool

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Ballot Results

Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits Implementation Plan AB 4 OT
Voting Start Date: 11/27/2020 12:01:00 AM
Voting End Date: 12/7/2020 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 267
Total Ballot Pool: 324
Quorum: 82.41
Quorum Established Date: 12/7/2020 4:38:34 PM
Weighted Segment Value: 89.79

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	92	1	65	0.878	9	0.122	0	5	13
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	75	1	49	0.907	5	0.093	0	4	17
Segment: 4	14	1	9	0.9	1	0.1	0	2	2
Segment: 5	71	1	49	0.907	5	0.093	0	5	12
Segment: 6	54	1	35	0.854	6	0.146	0	3	10
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	6	0.5	4	0.4	1	0.1	0	0	1
Totals:	324	6.4	220	5.747	27	0.653	0	20	57

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A

5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
6	Westar Energy	Grant Wilkerson		None	N/A
3	Westar Energy	Bryan Taggart		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A

3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
	Public Utility District No. 1 of Snohomish				

1	County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		None	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A

1	Lakeland Electric	Larry Watt		None	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		None	N/A
5	Florida Municipal Power Agency	Chris Gowder		Negative	Third-Party Comments
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Third-Party Comments
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A

5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

6	AEP	JT Kuehne		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Negative	Third-Party Comments
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Mickey Bellard		Abstain	N/A

3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		None	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A

6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Third-Party Comments
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
3	Omaha Public Power District	Aaron Smith		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A

5	National Grid USA	Elizabeth Spivak	None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt	Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Affirmative	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
6	Evergy	Thomas ROBBEN	Affirmative	N/A
1	Evergy	Allen Klassen	Affirmative	N/A
3	Evergy	Marcus Moor	Affirmative	N/A
5	Evergy	Derek Brown	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 Non-binding Poll AB 4 NB
Voting Start Date: 11/27/2020 12:01:00 AM
Voting End Date: 12/7/2020 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 250
Total Ballot Pool: 314
Quorum: 79.62
Quorum Established Date: 12/7/2020 5:23:39 PM
Weighted Segment Value: 71.79

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	86	1	41	0.707	17	0.293	14	14
Segment: 2	8	0.6	3	0.3	3	0.3	2	0
Segment: 3	75	1	31	0.721	12	0.279	12	20
Segment: 4	14	0.9	7	0.7	2	0.2	3	2
Segment: 5	68	1	30	0.732	11	0.268	13	14
Segment: 6	51	1	22	0.688	10	0.313	9	10
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	1	1
Segment:	1	0	0	0	0	0	0	1

9								
Segment: 10	7	0.5	5	0.5	0	0	1	1
Totals:	314	6.1	140	4.447	55	1.653	55	64

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A

6	Manitoba Hydro	Blair Mukanik	None	N/A
3	Manitoba Hydro	Mike Smith	None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome	Affirmative	N/A
3	Xcel Energy, Inc.	Ray Jasicki	Affirmative	N/A
3	JEA	Garry Baker	Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner	Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin	Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant	Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz	Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen	Abstain	N/A
6	Westar Energy	Grant Wilkerson	None	N/A
3	Westar Energy	Bryan Taggart	None	N/A
5	Nebraska Public Power District	Ronald Bender	Abstain	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy	Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall	Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan	Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
2	California ISO	Jamie Johnson	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Affirmative	N/A
1	Cleco Corporation	John Lindsey	Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell	Negative	Comments Submitted
5	Austin Energy	Michael Dillard	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel	None	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A

1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle Longo		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A

3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
7	Luminant Mining Company LLC	James Watson		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		None	N/A
5	Cleco Corporation	Stephanie Huffman		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
6	Entergy	Julie Hall		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		None	N/A
5	Florida Municipal Power Agency	Chris Gowder		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard		Negative	Comments

		Montgomery			Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
6	Muscatine Power and Water	Nick Burns		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Affirmative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Platte River Power Authority	Wade Kiess		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
6	AEP	JT Kuehne		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A

1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Mickey Bellard		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		None	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
6	Omaha Public Power District	Joel Robles		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A

1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
3	Omaha Public Power District	Aaron Smith		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A

3	Silicon Valley Power - City of Santa Clara	Val Ridad	None N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt	Affirmative N/A
1	Pacific Gas and Electric Company	Marco Rios	Affirmative N/A
1	Austin Energy	Thomas Standifur	Affirmative N/A
6	Evergy	Thomas ROBBEN	Affirmative N/A
1	Evergy	Allen Klassen	Affirmative N/A
3	Evergy	Marcus Moor	Affirmative N/A
5	Evergy	Derek Brown	Affirmative N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy	Affirmative N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative N/A

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20
45-day formal comment period with additional ballot	10/23/20 – 12/07/20

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2021
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority:
   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention:
   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

   1.3. Compliance Monitoring and Enforcement Program
   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL methodology”).
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective

			limiting Facility Ratings, System Voltage Limits or stability criteria	Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission

			Owner, and Generation Owner, but failed to provide them annually.	Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

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A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Planning Coordinator
   4.1.2. Reliability Coordinator
   4.1.3. Transmission Operator
   4.1.4. Transmission Planner
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology") ~~as established in FAC-011-4~~.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria	described in its respective Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed

			in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
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2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revised

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** by **8 p.m. Eastern, April 5, 2021.**

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Latrice Harkness, (via email), or at 404-446-9728.

Background Information

The Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. One of the primary objectives of Project 2015-09 is to make changes to the FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards and the revised definitions of Operational Planning Analysis (OPA) and Real-time Assessments (RTA).

In order to maintain consistency with CIP-002 criteria language, the standard drafting team (SDT) will not be modifying CIP-014 during this project. The applicability language regarding the derivation of IROLs will not be changed in CIP-014. The SDT has made significant enhancements in the Facilities Design, Connections, and Maintenance (FAC), Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards addressing issues with determining and communicating SOLs and Interconnection Reliability Operating Limits (IROLs). NERC is still evaluating approaches to the CIP-002 and CIP-014 language.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SDT made revisions to FAC-014-3 in response to comments, namely with the inclusion of time horizons on the subparts of R5 and an annual reporting requirement in R5.6. Do you agree with the revisions? If not, please explain why.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT received numerous comments regarding whether CIP-002.5.1a should be revised based upon the drafting team's revisions to FAC-011 and FAC-014. The SDT is not revising CIP-002.5.1a and provided a rationale document describing its reasoning with this posting. Do you agree with not revising CIP-002.5.1a and the reasoning provided? If not, please explain why?

   ☐ Yes
   ☐ No

   Comments:

3. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

   Comments:

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
<u>FAC-014-2, Requirements R3 and R4</u> R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 <u>FAC-011-4, Requirement R9, Part 9.2:</u> **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	planning any portion of the Reliability Coordinator Area; FAC-014-3 Requirement R6: **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning	

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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies at least once every twelve calendar months. IRO-014-3, Requirement R1 R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that	

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	require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.

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FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	1. FAC-014-3, Requirements R7 2. TPL-001-4, Requirement R8 FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a

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	instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the	PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	FAC-014-3, Requirement R7 (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are

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		communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL m~~M~~ethodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology (SOL ~~M~~methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology. R4. Each Reliability Coordinator shall establish stability limits ~~to be used in operations~~ when ~~the limit~~an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL ~~M~~methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL ~~M~~methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL ~~M~~methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because

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		the RC did not ensure that the TOP's SOL was consistent with its SOL ~~M~~methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly

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Coordinator Area that are consistent with its Reliability Coordinator's SOL ~~M~~methodology.	with its Reliability Coordinator's SOL ~~M~~methodology.	understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL ~~M~~methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL ~~M~~methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL ~~M~~methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3~~015-1~~, Requirement~~s~~ ~~R7~~R6 ~~R1 – R3~~ FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: ~~*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*~~ **9.2** Each of the following entities ~~30 days~~ prior to the effective date of the SOL methodology ~~or as soon as practicable if a change must be~~	The SDT is proposing a construct that does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL ~~M~~methodology. The PCs and T~~O~~Ps responsible for planning any portion of the RC's Area are made aware of the RC's SOL ~~M~~methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL ~~M~~methodology, PCs and TPs who plan any portion of the System in the

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	~~implemented in less than 30 days to address a reliability issue~~: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area; FAC-014-3~~015-1~~ Requirement R7~~6R1 – R3~~: **R~~7~~6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for	RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. ~~New Reliability Standard FAC-015-1 along with the changes in the P~~proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3~~015-1~~, Requirement~~s~~ R~~7~~6 ~~R1 – R3~~ ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those ~~established in accordance~~ described within the RC's SOL ~~M~~methodology. ~~FAC-015-1, Requirement R1 addresses Facility Ratings, Requirement R2 addresses the System steady state voltage limits, and Requirement R3~~

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	any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, ~~voltage criteria~~System steady-state voltage limits and stability criteria if it provides a technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator. ~~1. Each Planning Coordinator and each of its Transmission Planners, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~	~~addresses the stability performance criteria used in Planning Assessments. These requirements~~ FAC-014-3, Requirement R~~7~~6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability. ~~By implementing Requirements R1 – R3 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations.~~

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	• ~~The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan,~~ • ~~Facility Rating differences are due to variations in ambient temperature assumptions,~~ • ~~The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.~~ ~~2. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure that System steady-state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits used in operations per the Reliability~~	

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	~~Coordinator's SOL Methodology. The process may allow the use of less limiting System steady-state voltage limits if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ • ~~The Planning Coordinator provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provides a technical rationale for using a less limiting System steady-state voltage limit to each affected Planning Coordinator and Reliability Coordinator.~~ ~~3. Each Planning Coordinator and each of its Transmission Planners shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria used in operations per the Reliability Coordinator's SOL Methodology. The~~	

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	~~process may allow the use of less limiting stability performance criteria if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ • ~~The Planning Coordinator provides a technical rationale for using a less limiting stability performance criterion to each affected Transmission Planner and Reliability Coordinator, or~~ • ~~The Transmission Planner provides a technical rationale for using a less limiting stability performance criterion to each affected Planning Coordinator and Reliability Coordinator.~~	
FAC-014-2, Requirement R5, R5.1 R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities)	~~Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1.~~ While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3,

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information: R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) FAC-014-3, Requirement R5: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies);	Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	5.2.5. A description of ~~the associated~~ system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.~~5~~ 6 for each established stability limit ~~or~~and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies at least once every twelve calendar months. IRO-014-3, Requirement R1 R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources.	

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	1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator ~~in accordance with its Reliability Coordinator's SOL Methodology~~.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. ~~The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states:~~
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are	1. FAC-014-3~~015-1~~, Requirements ~~R7, R8R6,~~ R7 ~~R1 – R4~~ 2. TPL-001-4, Requirement R8	Provision of important planning study information to TOPs and RCs is preserved in ~~Reference the Ddescription and Change Justification above for~~

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	FAC-014-3~~015-1~~ Requirements ~~R76, ~~R~~8~~7 ~~**R1 – R3**~~ (Also ~~S~~see the t~~T~~ranslation above for Requirements R3 and R4~~ section above.~~) **R7.** Each Planning Coordinator and each Transmission Planner shall annually~~(?)~~ communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism, or unacceptable damping);	~~Requirements R3 and R4, which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-014-3015-1, R7.~~ ~~FAC-014-3015-1, Requirements R76 R1 – R3 results in PCs and TPs using Facility Ratings, System steady state voltage limits criteria, and stability performance criteria in their Planning Assessments of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the crtieria for Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance described within the RC's SOL Methodology.~~ FAC-014-3~~015-1~~, Requirement R7, which~~4~~ requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability~~, Cascading or uncontrolled separation~~ identified in ~~the~~ its Planning Assessments ~~and Transfer Capability assessments~~ to each impacted ~~RCs, TOPs, TOs, and GOs~~ TOP and RC. The subparts

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	7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. ~~**R4.** Each Planning Coordinator and each Transmission Planner shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include:~~ ~~**4.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~	of Requirement R~~7~~4 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. ~~This information is also necessarily communicated to TOs and GOs for their use in identifying Facilities that require higher levels of vegetative management or cyber protection.~~ TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware

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	~~**4.2** The associated stability criteria used as part of determining the instability;~~ ~~**4.3** The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;~~ ~~**4.4** A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified;~~ ~~**4.5** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;~~ ~~**4.6** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~ TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning	of any system performance issues identified by these Planning Assessments.

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	Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple	FAC-014-3~~015-1~~, Requirement ~~R4~~ ~~R8~~R7 (See the Translation above for Requirements R5.3 and R5.4 ~~section above.~~)	FAC-014-3~~015-1~~, Requirement ~~R6~~ R~~8~~7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7 addresses not only the identification of multiple contingencies that result in stability criteria violation ~~limits~~, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7

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contingencies, the Planning Authority shall so notify the Reliability Coordinator.		ensures the type of instability, ~~relevant~~ the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation ~~assumptions used by the PC~~ are communicated by the PC to the appropriate TOP and RC. • ~~Additionally, FAC-015-1, Requirement R4 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation.~~ • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3~~015-1~~, Requirement ~~R4~~ R~~8~~7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC ~~in accordance with FAC-015-1, Requirement R4~~. ~~In addition~~Further, it may be noted that FAC-014-2, Requirement R6,

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		R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3~~015-1~~, Requirement ~~R4s~~ R~~8~~7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	High
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology ("SOL methodology").

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**Medium**
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	**Medium**

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology ("SOL ~~M~~methodology")~~ as established in FAC-011-4~~.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.~~65~~6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	Medium~~High~~
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~mingle More than One Obligation~~	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria. ~~N/A~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	Medium

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement ~~R5.3 and~~R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R8	
Proposed VRF	Medium

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 -and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Technical Rationale for Reliability Standard FAC-014-3

February 2021

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC's documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC's SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC. It's important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication of SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

RCs who have asynchronous connections should consider the impact of all possible transfer levels across those connections including when those connections are not available if lost by contingency or forced outage.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, Requirement R5 Part 5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required ~~by ,~~by, Requirement R4 Part 4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under , Requirement R5 Part 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need more information from the RC on related SOLs in other TOP areas within the region that could impact their derivation. Requirement R5, Parts 5.3 through 5.5, require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and 4.1.1.3 in CIP-014. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC. The SDT also felt that some known periodicity of information provision, per this requirement, seemed appropriate. After industry comment, an annual periodicity was chosen. This timeframe should allow sufficient analysis to document IROLs that will persist, and need monitoring by the RC and any necessary action by asset owners, per the CIP standards. Those IROLs which may manifest in real time, due to forced outage

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models.

Analysis of these models determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:
Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor allow the PCs nor TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement. The obvious example for such an exception is a facility where the PC / TP has assumed an upgrade which increases the Facility Rating (typically, the thermal limit) of the equipment in question.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans, or the use of ambient temperature assumptions in seasonal planning models that differ from those ambient weather assumptions used in operational analyses and monitoring in real time, may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases due to upgrade are appropriately included in future planning models. These provisions should be included in the documented technical rationale provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Existing FAC-014-2, Requirement R6 requires similar, though less detailed, information is shared by the planning with the RC. The SDT believes FAC-014-3, Requirement R7, improves upon this requirement and provides added clear and concise information to its impacted RCs and TOPs.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation that adversely impacts the reliability of the BES to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Rationale R8

This requirement was drafted to ensure the appropriate details (i.e. Facilities) regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. Impacted Transmission and Generation Owners consist of those entities who have facilities requiring notification and **does not** imply that all Transmission and Generation Owners need notification of whether they have facilities requiring notification or not. This is necessary to ensure Facility owners receive this input to identify the Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT's proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement 5.6, provides annual notifications to Facility owners from both operating and planning entities, whereas no such timely notification requirements exist in the standards today.

Technical Rationale for Exclusion of CIP Criteria Modifications by Project 2015-09

February 2021

Introduction

The Project 2015-09 Standard Drafting Team (SDT) is proposing the retirement of the NERC FAC-010-3 - System Operating Limits Methodology for the Planning Horizon Reliability Standard. The SDT further proposes a new construct regarding the coordination of the Planning Assessment (TPL-001-4 - Transmission System Planning Performance Requirements) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new construct consists of substantial modifications to FAC-011-3 - System Operating Limits Methodology for the Operation Horizon and FAC-014-2 - Establish and Communicate System Operating Limits. These proposals together represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to prevent instability, Cascading or uncontrolled separation that adversely impact the reliability of the BES up to and including Real-time operations.

The proposed construct does not make use of an SOL methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4, and potential conflicts with the Reliability Coordinator's (RC) SOL methodology. During their discussion of FAC-010-3's retirement, the SDT concluded (with industry concurrence) that SOLs, and Interconnection Reliability Operating Limit (IROLs), only appropriate in the operations time horizon, and should not be determined in the planning horizon.

With these proposed changes to the FAC standards, and this conclusion regarding SOLs, the SDT was tasked with ensuring supplemental modifications were made, where necessary, to other Reliability Standards that made use of or referred to planning horizon SOLs. However, CIP-002-5.1a - Cyber Security — BES Cyber System Categorization and CIP-014-2 - Physical Security are not among the modification proposals despite the references, in attachments/applicability sections, to Planning Coordinator (PC)/Transmission Planner (TP) derived IROLs for use in the planning horizon. The remainder of this document provides a rationale for the SDT's exclusion of these two standards from the overall proposed modifications that result from the proposed retirement of FAC-010-3.

CIP Requirements for PC/TP Input

CIP-002.5.1a

Reliability Standard CIP-002.5.1a includes an attachment providing criteria that characterize the level of impact of CIP assets. The attachment includes 13 criteria (2.1 through 2.13) for the medium level. The first eight (8) criteria (2.1 through 2.8) focus on sets of transmission and generation facilities.

Criterion 2.6 in Attachment 1 of the standard states:

> *Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.*

Upon the retirement of FAC-010, this information would still be available from the RC via that information provided due to FAC-014 R5.6, but there would be no direct tie to PC/TP derived IROLs. The SDT does not view the retirement of FAC-010 as a potential reliability gap as it related to this criterion for the following reasons.

- The RC is currently solely responsible for determining IROLs needed for operating the BES reliably. Those IROLs exist for use by the RC and are shared with their Transmission Operators (TOPs). This does not change with the new SOL construct the SDT is proposing. In the new construct, the RC will continue to provide its IROLs to its TOPs and impacted planning entities. Additionally, the RC will provide information to the transmission and generation asset owners for their Facilities that are critical to the derivation of an IROL or its critical contingencies, at least annually. This ensures that all *"Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified … as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies"* are addressed with no gaps.

- Also in this new construct, PCs and TPs will continue to conduct their respective planning assessments in accordance with TPL-001 to identify system deficiencies and the respective Corrective Action Plans (CAPs) to address them. PCs and TPs will share with impacted RCs any information on CAPs they determine are needed to correct instances of instability found in their Planning Assessment of the Near-Term Transmission Planning Horizon (proposed FAC-014-3, Requirement R7). This provides the RC additional relevant information it needs from planning entities in its determination of SOLs, including IROLs. This ensures that all *"Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified … as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies"* include relevant input from the PC/TPs.

- Criterion 2.3 references generation Facilities identified by the PC/TP as necessary to avoid an Adverse Reliability Impact. This has significant overlap, as it relates to generation Facilities, to the Facilities that would also be identified by the RC as critical to the derivation of an IROL. It is important to note that the actual operating limit (referenced in criterion 2.6) is not the focus. Rather, the identification of the relevant generation plant is the focus; this plant, if lost or somehow compromised, could adversely impact the BES. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.

- Criterion 2.4 automatically qualifies Transmission Facilities operated at 500 kV or greater voltages to be in the medium impact category. This is regardless the reliability impact of a specific Facility that could be identified by planning studies. Since these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than lower voltage Facilities. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.
- Criterion 2.5 automatically qualifies Facilities operating between 200 kV and 499 kV based on the number of connections to other Transmission stations or substations. The basic premise in this criterion is to include “well-connected” BES substations as medium impact Facilities. Since these types of Facilities enable bulk power flow of the System, the impact identified by planning studies of the loss of one or more of these Facilities would generally produce more severe impacts than Facilities not as well connected to the System. This would also produce significant overlap to the Facilities identified by the RC in Criterion 2.6.
- TPL-001-4 Requirement R3 Parts 3.4 and 3.5 and Requirement R4 Parts 4.4 and 4.5 require the PC/TP to, in the annual Planning Assessment, identify and create a list of the planning and extreme events that are expected to produce “more severe System impacts.” These events may overlap those events that are critical to the derivation of an IROL. The transmission/generation owners can receive the annual Planning Assessment by request as a “functional entity with a reliability related need” per Requirement R8 of the standard.
- Proposed FAC-014-3 requires the PC/TP to annually communicate to impacted Transmission Owners and Generation Owners “their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.” This list of Facilities (for specific owners), covers all facilities the PC/TP would identify as critical to the derivation of an IROL under FAC-014-2 as it utilizes the components of the IROL definition (instability, Cascading, and uncontrolled separation that adversely impact the reliability of the Bulk Electric System) to describe the relevant Facilities as opposed to using the term itself.

In addition, the information provided by the RCs per FAC-014 R5.6 will be made available annually to the facility owners. Today there is no requirement that the information described in attachment 1 of CIP-002.5.1a be provided by any entity. FAC-014 R5.6 identifies an entity (the RC) and requires the information be submitted on regular basis (at least once annually). The annual submission requirement should address the concern noted by FERC in order 777 regarding the timeliness of CIP information provision. With an annual submission, the parties submitting the data should be able to provide the required information whether the data is created in an annual process (such as seasonal studies), or some other effort with a higher periodicity. The information recipients, the CIP asset owners, should be able to budget, plan and execute necessary projects accordingly knowing that they will receive the required information annually. If the RC deems an increased periodicity is needed, they can so act, but annual requirement set the minimum standard that all entities can use.

CIP-014-2

Reliability Standard CIP-014-2 enumerates the criteria (4.1.1.1 – 4.1.1.4) for Transmission Facilities to require physical security hardening. These criteria overlap those referenced above in CIP-002-5.1a.

Criterion 4.1.1.3 in the Applicability section of the standard states:

> *Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.*

This criterion is very similar to criterion 2.6 in CIP-002-5.1a as it relates to transmission facilities. Due to the similarities in the criteria, the same rationale stated for CIP-002-5.1a applies to CIP-014-2.

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Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through April 5, 2021

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, April 5, 2021** for the following standard:

- FAC-014-3 – Establish and Communicate System Operating Limit

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 26 – April 5, 2021**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Manager of Standards Development, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-09 Establish and Communicate System Operating Limits | FAC-014-3
Comment Period Start Date:	2/19/2021
Comment Period End Date:	4/5/2021
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 5 ST

There were 43 sets of responses, including comments from approximately 122 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT made revisions to FAC-014-3 in response to comments, namely with the inclusion of time horizons on the subparts of R5 and an annual reporting requirement in R5.6. Do you agree with the revisions? If not, please explain why.

2. The SDT received numerous comments regarding whether CIP-002.5.1a should be revised based upon the drafting team's revisions to FAC-011 and FAC-014. The SDT is not revising CIP-002.5.1a and provided a rationale document describing its reasoning with this posting. Do you agree with not revising CIP-002.5.1a and the reasoning provided? If not, please explain why?

3. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Del Viscio	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative	1	WECC
					Susan Sosbe	Wabash Valley Power Association	3	RF
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission	1	MRO

						Company, LLC		
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC

					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Helen Lainis	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC

					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC

					John Pearson	ISONE	2	NPCC
					John Hastings	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC

1. The SDT made revisions to FAC-014-3 in response to comments, namely with the inclusion of time horizons on the subparts of R5 and an annual reporting requirement in R5.6. Do you agree with the revisions? If not, please explain why.

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
In reviewing the language for requirement R5.4, the focus is on the Operational Planning Analysis, which NERC defines as a next day analysis. Given the NERC time horizon defintions (https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf), the only applicable time horizon appears to be Operations Planning since Same-day Operations applies to “the timeframe of a day” and Real-time Operations applies to “one hour or less”. In the alternative, if the drafting team believes these time horizons do apply, we recommend that the team update the rationale requirements document to explain how these other time horizons apply to the OPA.	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Scott Miller	
Answer	No
Document Name	
Comment	
Regarding the annual reporting requirement, Southern thinks it would be more appropriate to provide the information initially and then provide information as it changes, such as “within 90 days of a change.” Southern suggests that would be true for all of R5, not just R5.6.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
The standard is not results-based.	

Unfortunately, this project is six years old and needs to end.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company believes it is more appropriate to provide information initially and then provide information within a certain prescribed timeframe as the information changes. Several changes could occur within the annual period and users would not have the most up to date information. Additionally, the annual update is unnecessary if the information does not change.

The addition of the “Time Horizon” in R5.1-R5.6 does not provide useful clarification as R5 already indicates the applicable time horizons. Not only does this introduce un-necessary confusion for the RC in addressing the requirements, it appears to limit the flexibility in providing the SOL/IROL information the RC deems appropriate. For instance, it appears the RC is limited in R5.1 and R5.2 to only provide SOLs/IROLs identified in the Operations Planning time fame. Southern recommends removing the addition of the “Time Horizons” in R5.1-R5.6.

Likes 0	
Dislikes 0	

Response

Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5

Answer	No
Document Name	

Comment

See comments from Southern Company.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	Yes
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports Edison Electric Institute's response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the inclusion of “at least once every 12 months” to Requirement R5, Part 5.6, as well as the addition of Time Horizons to the various parts of Requirement R5.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
On behalf of Exelon (Segments 1, 3, 5, 6) Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	

Comment	
We support the revisions made by the SDT to FAC-014-3.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The IRC SRC appreciates the clarification made by the SDT to the language and applicable Time Horizons in Part 5.6 to specify "at least once every twelve calendar months." This timeframe should allow sufficient analysis to document IROLs that will persist and need monitoring by the Reliability Coordinator and any necessary action by asset owners, per CIP standards.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Truong Le - Truong Le On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; - Truong Le	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The SDT received numerous comments regarding whether CIP-002.5.1a should be revised based upon the drafting team's revisions to FAC-011 and FAC-014. The SDT is not revising CIP-002.5.1a and provided a rationale document describing its reasoning with this posting. Do you agree with not revising CIP-002.5.1a and the reasoning provided? If not, please explain why?

Truong Le - Truong Le On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; - Truong Le	
Answer	No
Document Name	
Comment	
Support Texas RE's comments.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE does not agree with not revising CIP-002-5.1. First, Texas RE notes that while PCs and TPs were removed from identifying IROLs in FAC-014, CIP-002 and CIP-014 still reference the PCs and TPs identifying Interconnection Reliability Operating Limits (IROLs). Second, since the RC does not have a timeframe for identifying SOLs, there could be a gap in that CIP protections may not occur for up to 24 months in accordance with the CIP-002-5.1 Implementation Plan.

Section 2.6 of the Impact Criteria of CIP-002-5.1, states that the PC and TP identify generation that is critical to the derivation of IROLs. Section 4.1.1.3 of the Applicability section of CIP-014-2 does this as well. However, FAC-014-3 removed the requirements for the PC and TP to establish IROLs. While the SDT indicates that PCs and TPs may continue to conduct planning assessments and provide Corrective Action Plans (CAPs) to address identified system deficiencies to their RCs, there ultimately is no definitive obligation within the NERC Reliability Standards for PCs and TPs to explicitly identify generation critical to the derivation of IROLs. From Texas RE's perspective, this results in reliability gaps because the TPL-001 planning assessment process does not explicitly incorporate the specific IROL derivation reliability task.

Texas RE believes that this gap has important consequences for the timing of the identification of IROLs and the corresponding implementation of CIP controls. Given that the TPs and PCs were removed from establishing IROLs in FAC-014-3, no identity is explicitly responsible for identifying IROLs in the planning horizon. Texas RE recommends explicitly keeping the TPs and PCs involved with this process in CIP-002 and CIP-014. Having the PCs and TPs conduct this analysis in the planning horizon many months or years prior to the IROL being established allows time for the generation and Transmission Facilities to establish CIP protections on the IROL.

Since FAC-014-3 does not include a time-frame specified for the RC to establish IROLs and no studies are required by the RC until a day prior to Real-time operations (OPA), the RC may not identify these Facilities before that point. Since the implementation plan for CIP-002-5.1 allows for an implementation period of 12 or 24 months depending on the scenario, this could result in a Facility that is determined to be critical to the derivation of an IROL not having adequate cyber and physical security controls for a period of up to 24 months.

This could be resolved by revising the impact criteria in CIP-002 and the applicability in CIP-014. In section 2.6 of the impact criteria for CIP-002, Texas RE recommends removing the reference to PCs and TPs, as they are no longer involved with identifying IROLs per FAC-14-3. Texas RE further recommends adding an additional criterion with the following verbiage: *Facilities identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.* This verbiage is consistent with the applicability section of FAC-003-5.

In CIP-014, Texas RE recommends revising section 4.1.1.3 of the Applicability to: *Facilities identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.*

These changes would explicitly allow for the PC and TPs to be involved with identifying Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. Doing this in the planning horizon will allow for the identified Facilities to establish CIP protections much earlier in the process, reducing the potential reliability issues posed by such critical Facilities.

Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

We agree that the CIP-002.5.1a criterion 2.6 can be retained without changes, but the Guidelines and Technical Basis as part of CIP-002-5.1a standard will need to be updated to reflect and align with FAC-014 R5 changes (see references cited for Criterion 2.6 at the bottom of page 25 and page 28 of CIP-002.5.1a). Without this linkage, Generator Owners or Transmission Owner receiving information pursuant to FAC-014-3 for the first time may fail to make the correlation to CIP-002-5.1a resulting in missing the identification of medium impct BES Facilities.

Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We support the SDT not revising CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	

Answer	Yes
Document Name	
Comment	
On behalf of Exelon (Segments 1, 3, 5, 6) Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the arguments contained in the Technical Rationale document titled “Technical Rationale for Exclusion of CIP Criteria Modifications by Project 2015-09” which addresses why there are no reliability gaps resulting from the retirement of FAC-010.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	

Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	

Comment	
CIP-002.5.1.a was already revised, vetted by industry and by NERC, approved by all, then submitted to FERC. Recently NERC withdrew it. The CIP virtualization project is also modifying it. Very confusing. Please no more changes.	
Likes 0	
Dislikes 0	
Response	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports Edison Electric Institute's response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

none	
Likes 0	
Dislikes 0	
Response	
Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Stevens - CPS Energy - 1,3,5

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Scott Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Nothing to add	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP has expressed its concerns in previous comment periods regarding the proposed revisions to FAC-014. A majority of those concerns and comments still stand and will not be restated again in their entirety in this current comment period. We would, however, like to offer the following thoughts and suggestions for consideration.

AEP thanks the drafting team for clarification on the meaning of "stability criteria" within R6. However, we find no reason why stability criteria consisting of acceptable power swing damping level, transient voltage dip and recovery durations, the necessity for the system to remain stable, and contingency definitions used in studies to evaluate stability would be any different in operations versus planning time-frames. We believe that the practical effect of including stability criteria in R6 will be to produce unnecessary administrative paperwork.

While we are somewhat encouraged that future consideration might be given to moving R6, R7 and R8 into TPL-001, we do remained concerned by the inference that this “move” might not happen until *after* these three requirements are first placed within FAC-014. We believe efforts to pursue such changes should be dealt with *only* as part of revising TPL-001, rather than *moving* them from FAC-014 to TPL-001 sometime in the future. As previously stated, rather than pursuing such changes within FAC-014, AEP recommends removing “stability criteria” from the proposed R6 and transferring the proposed R6, R7 and R8 over to a TPL-001 Standards Drafting Team. While well intentioned, we believe the Project 2015-09 Standards Drafting Team is unintentionally encroaching on the TPL domain by proposing such requirements be placed within FAC-014. These requirements are best served if drafted and reviewed from a Transmission Planner perspective, as these individuals would be in the best position to properly evaluate their necessity in view of the potential for nullification, or by possible reliance on operational actions and system adjustments not considered corrective action plans.

In closing, while AEP has once again chosen to vote negative as driven by the concerns stated above, we appreciate the efforts of the standards drafting team, and we envision potentially supporting such an effort provided a) “stability criteria” is removed from the proposed R6 and b) by dealing with R6, R7, and R8 solely within a project to revise TPL-001.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb

Answer	
Document Name	

Comment

Evergy incorporates by reference and supports Edison Electric Institute's response to Question 3.

Likes 0	
Dislikes 0	

Response

Jamie Johnson - California ISO - 2

Answer	
Document Name	

Comment

The CAISO Planning Coordinator recommends the following changes to the draft FAC-014-3 :

• Requirements R6 to R8 be removed from FAC-014-3.

•Requirement R6 is misplaced and should be addressed in TPL-001, which governs Planning Assessments, rather than in FAC-014-3. Keeping “like” requirements together in one standard will avoid inconsistency, retain the overall context of the requirements, increase efficiency, and avoid undue regulatory burden.

•Requirement R7 is also misplaced and should be addressed in TPL-001, which governs Planning Assessments, rather than in FAC-014-3. The comment above regarding keeping like requirements together applies here as well.

•Requirement R8 should be removed from FAC-014-3 because FAC-014-3 makes the Reliability Coordinator (RC) the sole functional entity that establishes IROLs. As such, the PC and the TP that no longer establish IROLs should not be required to provide facilities that are critical to the derivation of IROLs and their contingencies to the impacted Transmission Owner (TO) and Generation Owner (GO) in accordance with CIP-002, CIP-014, etc. Requirement R5.6, which requires the RC to provide such information to the impacted TO and GO, should be sufficient to address their IROL-related needs. If the SDT determines there is Planning Assessment related information that the PC and TP should provide to the TO and GO, the requirement should be addressed in TPL-001 that governs their Planning Assessment, rather than in FAC-014, to keep like requirements together. Also, because TPL-001 does not allow planning event Contingency(ies) to cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES, Requirement R8 is inconsistent with TPL-001.

• The phrase “ and that Planning Assessment performance criteria is coordinated with these methodologies.” be removed from the Purpose (Section 3) of FAC-014-3.

• The Planning Coordinator and the Transmission Planner be removed from the Applicability Section (Section 4).

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

RE: R5.2.4 The associated **critical** Contingency(ies): We request the Standard Drafting Team clarify the use of the word “critical” to describe Contingency(ies)” noting that “**critical** Contingency(ies)” is undefined and opens Requirement R5, subpart 5.2.4 to interpretation.

Please consider revising the subparts of 5.2 (Requirement R5) as follows:

5.2.1 The value of the stability limit or IROL;
5.2.2 The associated IROL Tv for any IROL;
5.2.3 ***Identification of the Facilities that are critical to the derivation of the stability limit or the IROL and the associated Contingency(ies);***
5.2.4 A description of system conditions associated with the stability limit or IROL; and
5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

Comments:

- · Suggest the coordination of methodologies, limits, criteria, etc, by the RC with the PC/TP should occur earlier in the RC's process.
- · Suggest the RC should be requesting review and comments from the PC/TP.

o The RC should align as much as possible with the PC/TP's criteria as the PC/TP determines what adequate investment into the system is.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	
Document Name	
Comment	
not at this time, thank you.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
Let move foward with the Standards Effieciency Review Porject to get rid of non Results based Standards, redunancy in Standards, and inefficiencies.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	

Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Thank you for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	
Document Name	
Comment	

CPS Energy does not have any comments.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

Requirement R6 is confusingly written, mainly because it confuses the concept of “criteria” and the use of components of criteria.

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits and**/or** stability **criteria used**, as described in its respective Reliability Coordinator's SOL methodology.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	

Comment

Changes to R6-R8 may be perceived as an attempt of the SDT to modify TPL-001 and MOD-032. In addition, the proposed changes to FAC-014-3 appears to be an attempt to possibly require additional information and additional coordination between operations and planning. If the SDT feels strongly that these modifications to TPL-001 and MOD-032 are required to support the reliable operation of the BES Facilities, it may be be of benefit of the SDT to submit a SAR for TPL-001 and MOD-032 instead of spreading the requirement out across multiple standards.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The IRC continues to believe that the drafting team should be given the opportunity to address efficiencies identified by the Standards Efficiency Review Project to reduce redundancy in the requirements and exposure to double jeopardy. FAC-013-3 R7 proposed to annually share CAP's with RC's and TOP's. IRO-017 R3 already has the requirement to share the CAP's with RC's. FAC-014-3, continues to say what should be included in that CAP, while TPL-001-4 R2.7 provides the initial requirement for completing a CAP and what should be included.

The IRC SRC continues to believe that the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The IRC SRC recommends that consistent terminology be used across these standards.

- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The IRC SRC recommends that consistent terminology be used across these standards.

In addition, the IRC SRC continues to recommend that the following change be made to R6 to clarify the intent of the requirement:

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady state Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the the criteria ***for the use*** of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

The IRC continues to believe there is confusion with in this requirement. Facility Ratings are provided by asset owners. Is that the case for System Voltage Limits as well.

Finally, from a proofreading perspective, the IRC SRC notes there is an incomplete sentence (located as the last sentence in paragraph 2) on page 6 of the **Technical Rationale for Reliability Standard FAC-014-3** : "Those IROLs which may manifest in real time, due to forced outage…" that needs to be completed or deleted.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA continues to be concerned that the Technical Rationale document is apart from the Standard. There appears to be risks asscociated with this approach as neither an entity nor an auditor are required to consider Technical Rationale guidance when implementing requirements or performing audits, respectively. To remove this potential compliance issue, BPA believes language requiring Facility Ratings and system voltage limits to be equally limiting or more limiting than what's provided by the TOP in accordance with its RC's SOL methodology needs to be explicitly stated in the Standard.

Furthermore, BPA believes language requiring that criteria developed and documented for stability performance be equally limiting or more limiting than the criteria in its respective RC's SOL methodology needs to be explicitly stated in the Standard.

In consideration of the SDT's comments with regard to the word 'ensure', BPA offers revisions to its comments regarding R6 to replace 'ensure' with 'require'. See below.

R6. Each Planning Coordinator and each Transmission Planner shall ***require*** that Facility Ratings and system voltage limits used in its Planning Assessment of the Near Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings and system voltage limits provided by the TOP to its RC in accordance with its Reliability Coordinator's SOL methodology.

In addition, each Planning Coordinator and each Transmission Planner shall ***require*** that criteria developed and documented for stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for stability specified in its respective Reliability Coordinator's SOL methodology. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT appreciates the Standard Drafting Team's revision to the rationale accompanying Requirement R8.

For purposes of further clarification, is Requirement R8 intended to mean that only the owners of the facilities that comprise the planning event contingency(ies) that cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in the near-term planning assessment need to be notified that certain specific facilities they own are part of a planning event contingency that would cause cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES?

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

A new NERC time-horizon should be created, termed "Day-Ahead Operations" – operating and resource plans within the day ahead timeframe, to replace the Operations Planning Horizon applicability of R1 through R5 consistent with the intended horizon of SOL exceedance determinations.

Likes 0	
Dislikes 0	

Response

Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5

Answer	
Document Name	

Comment

See comments from Southern Company.

Likes 0	
Dislikes 0	
Response	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2015-09 Establish and Communicate System Operating Limits | FAC-014-3
Comment Period Start Date:	2/19/2021
Comment Period End Date:	4/5/2021
Associated Ballots:	2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 5 ST

There were 43 sets of responses, including comments from approximately 122 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

1. The SDT made revisions to FAC-014-3 in response to comments, namely with the inclusion of time horizons on the subparts of R5 and an annual reporting requirement in R5.6. Do you agree with the revisions? If not, please explain why.

2. The SDT received numerous comments regarding whether CIP-002.5.1a should be revised based upon the drafting team's revisions to FAC-011 and FAC-014. The SDT is not revising CIP-002.5.1a and provided a rationale document describing its reasoning with this posting. Do you agree with not revising CIP-002.5.1a and the reasoning provided? If not, please explain why?

3. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Del Viscio	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kahtleen Goodman	ISO-NE	2	NPCC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC

					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					David Hartman	Arizona Electric Power Cooperative	1	WECC
					Susan Sosbe	Wabash Valley Power Association	3	RF

DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO

					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO

					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC

					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State	7	NPCC

	Reliability Council		
David Burke	Orange & Rockland Utilities	3	NPCC
Helen Lainis	IESO	2	NPCC
David Kiguel	Independent	7	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC

					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State	10	NPCC

						Reliability Council		
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC
					John Pearson	ISONE	2	NPCC
					John Hastings	National Grid USA	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC

1. The SDT made revisions to FAC-014-3 in response to comments, namely with the inclusion of time horizons on the subparts of R5 and an annual reporting requirement in R5.6. Do you agree with the revisions? If not, please explain why.

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
In reviewing the language for requirement R5.4, the focus is on the Operational Planning Analysis, which NERC defines as a next day analysis. Given the NERC time horizon defintions (https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf), the only applicable time horizon appears to be Operations Planning since Same-day Operations applies to "the timeframe of a day" and Real-time Operations applies to "one hour or less". In the alternative, if the drafting team believes these time horizons do apply, we recommend that the team update the rationale requirements document to explain how these other time horizons apply to the OPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement 5.3 in FAC-014-3 provides the value for the stability limits established by the RC per requirements 1 and 4 for use in Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. For established IROLs, the SDT thought requirement 5.4 only made sense in the Operational Planning Analysis "space" to provide all of the information indicated per Requirement Parts 5.2.2 – 5.2.6. These standards merely set the "floor" for what is required, and an RC and its TOPs can agree on additional information to be shared Same-day Operations and Real-time Operations.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Scott Miller	
Answer	No
Document Name	

Comment	
Regarding the annual reporting requirement, Southern thinks it would be more appropriate to provide the information initially and then provide information as it changes, such as “within 90 days of a change.” Southern suggests that would be true for all of R5, not just R5.6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The SDT considered a number of potential reporting schemes, and after listening to feedback from the SDT members and industry, settled on the “at least once every 12 months” timeframe. This time-reference does not preclude an RC from providing the information more frequently if so desired, but merely establishes a common frame for the industry, and allows entities sufficient time to evaluate changes to the information, as well as those entities receiving the information time to prepare receipt and action based upon the information.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
The standard is not results-based. Unfortunately, this project is six years old and needs to end.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	No
Document Name	
Comment	
Southern Company believes it is more appropriate to provide information initially and then provide information within a certain prescribed timeframe as the information changes. Several changes could occur within the annual period and users would not have the most up to date information. Additionally, the annual update is unnecessary if the information does not change. The addition of the “Time Horizon” in R5.1-R5.6 does not provide useful clarification as R5 already indicates the applicable time horizons. Not only does this introduce un-necessary confusion for the RC in addressing the requirements, it appears to limit the flexibility in providing the SOL/IROL information the RC deems appropriate. For instance, it appears the RC is limited in R5.1 and R5.2 to only provide SOLs/IROLs identified in the Operations Planning time fame. Southern recommends removing the addition of the “Time Horizons” in R5.1-R5.6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The SDT considered a number of potential reporting schemes, and after listening to feedback from the SDT members and industry, settled on the “at least once every 12 months” timeframe. This time-reference does not preclude an RC from providing the information more frequently if so desired, but merely establishes a common frame for the industry, and allows entities sufficient time to evaluate changes to the information, as well as those entities receiving the information time to prepare receipt and action based upon the information. Many commenters requested clarification on the applicable Time Horizon for the requirements in FAC-014-3, and seemed to appreciate the applied entries. As noted above, these merely establish a minimum common basis for industry, and can be exceeded with agreement between the RC and those interested parties.	
Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5	

Answer	No
Document Name	
Comment	
See comments from Southern Company.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our responses to Southern Company.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Evergy incorporates by reference and supports Edison Electric Institute's response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to Edison Electric Institute.	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the ISO/RTO Council (IRC) Standards Review Committee.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	

Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the MRO NSRF comments.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see our response to Edison Electric Institute.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to the MRO NSRF comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the inclusion of “at least once every 12 months” to Requirement R5, Part 5.6, as well as the addition of Time Horizons to the various parts of Requirement R5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Daniel Gacek - Exelon - 1	

Answer	Yes
Document Name	
Comment	
On behalf of Exelon (Segments 1, 3, 5, 6) Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to EEI's comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We support the revisions made by the SDT to FAC-014-3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	

Answer	Yes
Document Name	
Comment	
The IRC SRC appreciates the clarification made by the SDT to the language and applicable Time Horizons in Part 5.6 to specify "at least once every twelve calendar months." This timeframe should allow sufficient analysis to document IROLs that will persist and need monitoring by the Reliability Coordinator and any necessary action by asset owners, per CIP standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Stevens - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Truong Le - Truong Le On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; - Truong Le	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The SDT received numerous comments regarding whether CIP-002.5.1a should be revised based upon the drafting team's revisions to FAC-011 and FAC-014. The SDT is not revising CIP-002.5.1a and provided a rationale document describing its reasoning with this posting. Do you agree with not revising CIP-002.5.1a and the reasoning provided? If not, please explain why?

Truong Le - Truong Le On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Dale Ray, Florida Municipal Power Agency, 6, 4, 5, 3; - Truong Le

Answer	No
Document Name	

Comment

Support Texas RE's comments.

Likes 0	
Dislikes 0	

Response

Please see response to Texas RE.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE does not agree with not revising CIP-002-5.1. First, Texas RE notes that while PCs and TPs were removed from identifying IROLs in FAC-014, CIP-002 and CIP-014 still reference the PCs and TPs identifying Interconnection Reliability Operating Limits (IROLs). Second, since the RC does not have a timeframe for identifying SOLs, there could be a gap in that CIP protections may not occur for up to 24 months in accordance with the CIP-002-5.1 Implementation Plan.

Section 2.6 of the Impact Criteria of CIP-002-5.1, states that the PC and TP identify generation that is critical to the derivation of IROLs. Section 4.1.1.3 of the Applicability section of CIP-014-2 does this as well. However, FAC-014-3 removed the requirements for the PC and TP to establish IROLs. While the SDT indicates that PCs and TPs may continue to conduct planning assessments and provide Corrective Action Plans (CAPs) to address identified system deficiencies to their RCs, there ultimately is no definitive obligation within the NERC Reliability Standards for PCs and TPs to explicitly identify generation critical to the derivation of IROLs. From Texas RE's perspective, this results in reliability gaps because the TPL-001 planning assessment process does not explicitly incorporate the specific IROL derivation reliability task.

Texas RE believes that this gap has important consequences for the timing of the identification of IROLs and the corresponding implementation of CIP controls. Given that the TPs and PCs were removed from establishing IROLs in FAC-014-3, no identity is explicitly responsible for identifying IROLs in the planning horizon. Texas RE recommends explicitly keeping the TPs and PCs involved with this process in CIP-002 and CIP-014. Having the PCs and TPs conduct this analysis in the planning horizon many months or years prior to the IROL being established allows time for the generation and Transmission Facilities to establish CIP protections on the IROL.

Since FAC-014-3 does not include a time-frame specified for the RC to establish IROLs and no studies are required by the RC until a day prior to Real-time operations (OPA), the RC may not identify these Facilities before that point. Since the implementation plan for CIP-002-5.1 allows for an implementation period of 12 or 24 months depending on the scenario, this could result in a Facility that is determined to be critical to the derivation of an IROL not having adequate cyber and physical security controls for a period of up to 24 months.

This could be resolved by revising the impact criteria in CIP-002 and the applicability in CIP-014. In section 2.6 of the impact criteria for CIP-002, Texas RE recommends removing the reference to PCs and TPs, as they are no longer involved with identifying IROLs per FAC-14-3. Texas RE further recommends adding an additional criterion with the following verbiage: *Facilities identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment*

(Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. This verbiage is consistent with the applicability section of FAC-003-5. In CIP-014, Texas RE recommends revising section 4.1.1.3 of the Applicability to: *Facilities identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.* These changes would explicitly allow for the PC and TPs to be involved with identifying Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. Doing this in the planning horizon will allow for the identified Facilities to establish CIP protections much earlier in the process, reducing the potential reliability issues posed by such critical Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT notes that Section 2.6 of the Impact Criteria of CIP-002-5.1 identifies that “IF” a PC or TP were to identify such facilities, they would have to be taken into consideration. This criteria does not obligate a PC or TP to identify these items. Because a PC or TP do not identify “operating” limits, including IROLs, the RC is the correct functional entity to identify IROLs and the facilities critical to the derivation of the IROL and its associated contingencies. While the SDT agrees that a future modification to CIP-002-5.1 can remove such references, the SDT still contends that there is no reliability gap created as the RC still identifies all IROLs. The SDT does not believe it is appropriate for the PC or TP to establish IROLs as IROLs are “operating” limits. The RC typically evaluates more operating conditions than the planning horizon studies and has additional outages to contend with. Additionally, the RC can better determine which contingencies to consider. While these studies are often conducted well in advance of next day operations (up to one year), this allows for the proper identification and establishment of these operating limits. It would not be practical to establish security controls until the RC who is the entity to establish the “operating” limit has evaluated and determined the facilities critical to the derivation of an IROL. The SDT	

notes that there are several other criterion where the facilities are identified via other criteria or where it is appropriate for the PC/TP to identify facilities (2.3). The SDT notes the concern, but believes this concern would be present with either version of FAC-014 (current or new) and is outside the scope of the SDT's SAR to address the implementation period of the security controls. The SDT contends that the facilities related to the IROLs are better clarified to be the responsibility of the RC and that there is no reliability gap created. If a CIP SDT would want to modify the implementation period or determine a different criterion is better suited than an IROL, the CIP SDT should address such changes. The SDT contends that the facilities related to the IROLs are better clarified to be the responsibility of the RC and that there is no reliability gap created. If a CIP SDT would want to modify the implementation period or determine a different criterion is better suited than an IROL, the CIP SDT should address such changes.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
We agree that the CIP-002.5.1a criterion 2.6 can be retained without changes, but the Guidelines and Technical Basis as part of CIP-002-5.1a standard will need to be updated to reflect and align with FAC-014 R5 changes (see references cited for Criterion 2.6 at the bottom of page 25 and page 28 of CIP-002.5.1a). Without this linkage, Generator Owners or Transmission Owner receiving information pursuant to FAC-014-3 for the first time may fail to make the correlation to CIP-002-5.1a resulting in missing the identification of medium impct BES Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

We support the SDT not revising CIP-002-5.1a.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
On behalf of Exelon (Segments 1, 3, 5, 6) Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the arguments contained in the Technical Rationale document titled “Technical Rationale for Exclusion of CIP Criteria Modifications by Project 2015-09” which addresses why there are no reliability gaps resulting from the retirement of FAC-010.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	

Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
CIP-002.5.1.a was already revised, vetted by industry and by NERC, approved by all, then submitted to FERC. Recently NERC withdrew it. The CIP virtualization project is also modifying it. Very confusing. Please no more changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Johnson - California ISO - 2	
Answer	Yes
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Council (IRC) Standards Review Committee.	
Likes 0	
Dislikes 0	
Response	
Please see response to ISO/RTO Council (IRC) Standards Review Committee.	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Evergy incorporates by reference and supports Edison Electric Institute's response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Scott Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. If you have any other comments regarding FAC-014-3 that you haven't already provided, please provide them here.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
Nothing to add	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	

Answer	
Document Name	
Comment	

AEP has expressed its concerns in previous comment periods regarding the proposed revisions to FAC-014. A majority of those concerns and comments still stand and will not be restated again in their entirety in this current comment period. We would, however, like to offer the following thoughts and suggestions for consideration.

AEP thanks the drafting team for clarification on the meaning of “stability criteria” within R6. However, we find no reason why stability criteria consisting of acceptable power swing damping level, transient voltage dip and recovery durations, the necessity for the system to remain stable, and contingency definitions used in studies to evaluate stability would be any different in operations versus planning time-frames. We believe that the practical effect of including stability criteria in R6 will be to produce unnecessary administrative paperwork.

While we are somewhat encouraged that future consideration might be given to moving R6, R7 and R8 into TPL-001, we do remained concerned by the inference that this “move” might not happen until *after* these three requirements are first placed within FAC-014. We believe efforts to pursue such changes should be dealt with *only* as part of revising TPL-001, rather than *moving* them from FAC-014 to TPL-001 sometime in the future. As previously stated, rather than pursuing such changes within FAC-014, AEP recommends removing “stability criteria” from the proposed R6 and transferring the proposed R6, R7 and R8 over to a TPL-001 Standards Drafting Team. While well intentioned, we believe the Project 2015-09 Standards Drafting Team is unintentionally encroaching on the TPL domain by proposing such requirements be placed within FAC-014. These requirements are best served if drafted and reviewed from a Transmission Planner perspective, as these individuals would be in the best position to properly evaluate their necessity in view of the potential for nullification, or by possible reliance on operational actions and system adjustments not considered corrective action plans.

In closing, while AEP has once again chosen to vote negative as driven by the concerns stated above, we appreciate the efforts of the standards drafting team, and we envision potentially supporting such an effort provided a) “stability criteria” is removed from the proposed R6 and b) by dealing with R6, R7, and R8 solely within a project to revise TPL-001.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Evergy, 6, 1, 3, 5; Derek Brown, Evergy, 6, 1, 3, 5; Marcus Moor, Evergy, 6, 1, 3, 5; Thomas ROBBEN, Evergy, 6, 1, 3, 5; - Douglas Webb	
Answer	
Document Name	
Comment	
Evergy incorporates by reference and supports Edison Electric Institute's response to Question 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see our response to EEI.	

Jamie Johnson - California ISO - 2	
Answer	
Document Name	
Comment	

The CAISO Planning Coordinator recommends the following changes to the draft FAC-014-3 :

• Requirements R6 to R8 be removed from FAC-014-3.

•Requirement R6 is misplaced and should be addressed in TPL-001, which governs Planning Assessments, rather than in FAC-014-3. Keeping “like” requirements together in one standard will avoid inconsistency, retain the overall context of the requirements, increase efficiency, and avoid undue regulatory burden.

•Requirement R7 is also misplaced and should be addressed in TPL-001, which governs Planning Assessments, rather than in FAC-014-3. The comment above regarding keeping like requirements together applies here as well.

•Requirement R8 should be removed from FAC-014-3 because FAC-014-3 makes the Reliability Coordinator (RC) the sole functional entity that establishes IROLs. As such, the PC and the TP that no longer establish IROLs should not be required to provide facilities that are critical to the derivation of IROLs and their contingencies to the impacted Transmission Owner (TO) and Generation Owner (GO) in accordance with CIP-002, CIP-014, etc. Requirement R5.6, which requires the RC to provide such information to the impacted TO and GO, should be sufficient to address their IROL-related needs. If the SDT determines there is Planning Assessment related information that the PC and TP should provide to the TO and GO, the requirement should be addressed in TPL-001 that governs their Planning Assessment, rather than in FAC-014, to keep like requirements together. Also, because TPL-001 does not allow planning event Contingency(ies) to cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES, Requirement R8 is inconsistent with TPL-001.

• The phrase “ and that Planning Assessment performance criteria is coordinated with these methodologies.” be removed from the Purpose (Section 3) of FAC-014-3.

• The Planning Coordinator and the Transmission Planner be removed from the Applicability Section (Section 4).

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. As discussed in responses to our the previous posting of FAC-014-3 regarding the comments to R7 and R8, future consideration will be given to moving R6, R7 and R8 into TPL-001.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
RE: R5.2.4 The associated **critical** Contingency(ies): We request the Standard Drafting Team clarify the use of the word "critical" to describe Contingency(ies)" noting that "**critical** Contingency(ies)" is undefined and opens Requirement R5, subpart 5.2.4 to interpretation. Please consider revising the subparts of 5.2 (Requirement R5) as follows: 5.2.1 The value of the stability limit or IROL; 5.2.2 The associated IROL Tv for any IROL; *5.2.3* ***Identification of the Facilities that are critical to the derivation of the stability limit or the IROL and the associated Contingency(ies);*** 5.2.4 A description of system conditions associated with the stability limit or IROL; and 5.2.5 The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. As per responses to comments in the previous posting the term "critical" is used throughout the standards especially pertaining to facilities. As Contingencies can comprise of such facilities, the SDT believes the language proposed in requirement part 5.2 is clear.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

Comments:

- · Suggest the coordination of methodologies, limits, criteria, etc, by the RC with the PC/TP should occur earlier in the RC's process.
- · Suggest the RC should be requesting review and comments from the PC/TP.

o The RC should align as much as possible with the PC/TP's criteria as the PC/TP determines what adequate investment into the system is.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The new and modified requirements were designed to simply require that the PC/TP is aware of the latest changes to SOL/IROLs and related information but does not specify when in the RC processes this should take place. This allows flexibility for the RC, and PC/TP to determine coordination details for carrying out the requirement.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	

Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NERC Standards Review Forum comments.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
not at this time, thank you.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

Let move foward with the Standards Effieciency Review Porject to get rid of non Results based Standards, redunancy in Standards, and inefficiencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Thank you for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Please see response to MRC NERC Standards Review Forum.	
Gladys DeLaO - CPS Energy - 1	
Answer	
Document Name	
Comment	
CPS Energy does not have any comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wayne Guttormson - SaskPower - 1	
Answer	

Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
Requirement R6 is confusingly written, mainly because it confuses the concept of “criteria” and the use of components of criteria. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits and**/or** stability **criteria used**, as described in its respective Reliability Coordinator’s SOL methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF	
Aidan Gallegos - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
Changes to R6-R8 may be perceived as an attempt of the SDT to modify TPL-001 and MOD-032. In addition, the proposed changes to FAC-014-3 appears to be an attempt to possibly require additional information and additional coordination between operations and planning. If the SDT feels strongly that these modifications to TPL-001 and MOD-032 are required to support the reliable operation of the BES Facilities, it may be be of benefit of the SDT to submit a SAR for TPL-001 and MOD-032 instead of spreading the requirement out across multiple standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Future consideration will be given to these requirements moving into other standards.	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	

Document Name	
Comment	

The IRC continues to believe that the drafting team should be given the opportunity to address efficiencies identified by the Standards Efficiency Review Project to reduce redundancy in the requirements and exposure to double jeopardy. FAC-013-3 R7 proposed to annually share CAP's with RC's and TOP's. IRO-017 R3 already has the requirement to share the CAP's with RC's. FAC-014-3, continues to say what should be included in that CAP, while TPL-001-4 R2.7 provides the initial requirement for completing a CAP and what should be included.

The IRC SRC continues to believe that the following additional changes to the language in the requirement:

- FAC-011-4 uses the phrase, "System Voltage Limits" (see FAC-011-4 R3). FAC-014 R6 uses a mix of terms such as "System steady state voltage limits" as well as "System Voltage Limits". The IRC SRC recommends that consistent terminology be used across these standards.

- FAC-011-4 uses the phrases, "stability limits", and "stability performance criteria" (see FAC-011-4 R4). FAC-014 R6 uses a mix of terms such as "stability criteria" or just "stability". The IRC SRC recommends that consistent terminology be used across these standards.

In addition, the IRC SRC continues to recommend that the following change be made to R6 to clarify the intent of the requirement:

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady state Voltage Limits and stability criteria in its Planning Assessment of the Near Term Transmission Planning Horizon that are equally limiting or more limiting than the the criteria ***for the use*** of Facility Ratings, System Voltage Limits and stability criteria described in its respective Reliability Coordinator's SOL methodology.

The IRC continues to believe there is confusion with in this requirement. Facility Ratings are provided by asset owners. Is that the case for System Voltage Limits as well.

Finally, from a proofreading perspective, the IRC SRC notes there is an incomplete sentence (located as the last sentence in paragraph 2) on page 6 of the **Technical Rationale for Reliability Standard FAC-014-3** : “Those IROLs which may manifest in real time, due to forced outage…” that needs to be completed or deleted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Regarding standards efficiency and redundancy, the drafting team understands the concerns and the responses made to the previous set of comments remains valid. Thank you for noting the incomplete sentence for us to correct.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA continues to be concerned that the Technical Rationale document is apart from the Standard. There appears to be risks asscociated with this approach as neither an entity nor an auditor are required to consider Technical Rationale guidance when implementing requirements or performing audits, respectively. To remove this potential compliance issue, BPA believes language requiring Facility Ratings and system voltage limits to be equally limiting or more limiting than what’s provided by the TOP in accordance with its RC’s SOL methodology needs to be explicitly stated in the Standard. Furthermore, BPA believes language requiring that criteria developed and documented for stability performance be equally limiting or more limiting than the criteria in its respective RC’s SOL methodology needs to be explicitly stated in the Standard. In consideration of the SDT's comments with regard to the word ‘ensure’, BPA offers revisions to its comments regarding R6 to replace ‘ensure’ with ‘require’. See below.	

R6. Each Planning Coordinator and each Transmission Planner shall ***require*** that Facility Ratings and system voltage limits used in its Planning Assessment of the Near Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings and system voltage limits provided by the TOP to its RC in accordance with its Reliability Coordinator's SOL methodology. In addition, each Planning Coordinator and each Transmission Planner shall ***require*** that criteria developed and documented for stability performance for its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the criteria for stability specified in its respective Reliability Coordinator's SOL methodology. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. They were considered, however, the SDT believes the Requirement R6 and its rationale are clear enough as written.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT appreciates the Standard Drafting Team's revision to the rationale accompanying Requirement R8. For purposes of further clarification, is Requirement R8 intended to mean that only the owners of the facilities that comprise the planning event contingency(ies) that cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in the near-term planning assessment need to be notified that certain specific facilities they own are part of a planning event contingency that would cause cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES?	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The answer to your question is yes. In line with the SDT's response to ERCOT's comments in the previous posting, Requirement R8 is intended to clarify that only the TO and GO with identified facilities would be included in the communication from the PC & TP.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
A new NERC time-horizon should be created, termed "Day-Ahead Operations" – operating and resource plans within the day ahead timeframe, to replace the Operations Planning Horizon applicability of R1 through R5 consistent with the intended horizon of SOL exceedance determinations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rob Watson - Choctaw Generation Limited Partnership, LLLP - 5	
Answer	
Document Name	
Comment	

See comments from Southern Company.	
Likes 0	
Dislikes 0	
Response	
Please see response to Southern Company.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Formal Comment Period Open through April 5, 2021

Now Available

A 45-day formal comment period is open through **8 p.m. Eastern, Monday, April 5, 2021** for the following standard:

- FAC-014-3 – Establish and Communicate System Operating Limit

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 26 – April 5, 2021**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2015-09 Establish and Communicate System Operating Limits” in the Description Box. For more information or assistance, contact Manager of Standards Development, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Comment: View Comment Results
Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 AB 5 ST
Voting Start Date: 3/26/2021 12:01:00 AM
Voting End Date: 4/5/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 5
Total # Votes: 263
Total Ballot Pool: 325
Quorum: 80.92
Quorum Established Date: 4/5/2021 4:21:44 PM
Weighted Segment Value: 92.35

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	92	1	68	0.919	6	0.081	0	6	12
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	74	1	50	0.943	3	0.057	0	3	18
Segment: 4	15	1	11	1	0	0	0	2	2
Segment: 5	70	1	47	0.904	5	0.096	0	2	16
Segment: 6	54	1	35	0.921	3	0.079	0	4	12
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	1	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	325	6.7	226	6.187	19	0.513	0	18	62

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A

5	Manitoba Hydro	Yuguang Xiao		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Grant Wilkerson		None	N/A
3	Westar Energy	Bryan Taggart		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		Affirmative	N/A

3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	PPL Electric Utilities Corporation	Preston Walker		Affirmative	N/A

5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A

1	Lakeland Electric	Larry Watt		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A

5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A

3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A

1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy	Affirmative	N/A

			Fuhrman		
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

6	Evergy	Thomas ROBBEN	Affirmative N/A
1	Evergy	Allen Klassen	Affirmative N/A
3	Evergy	Marcus Moor	Affirmative N/A
5	Evergy	Derek Brown	Affirmative N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy	Affirmative N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative N/A

[redacted]

NERC Balloting Tool

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Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 Non-binding Poll AB 5 NB
Voting Start Date: 3/26/2021 12:01:00 AM
Voting End Date: 4/5/2021 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 5
Total # Votes: 243
Total Ballot Pool: 313
Quorum: 77.64
Quorum Established Date: 4/5/2021 6:52:11 PM
Weighted Segment Value: 92.97

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	85	1	50	0.943	3	0.057	18	14
Segment: 2	8	0.6	6	0.6	0	0	2	0
Segment: 3	75	1	37	0.925	3	0.075	14	21
Segment: 4	14	1	10	1	0	0	2	2
Segment: 5	68	1	36	0.9	4	0.1	10	18
Segment: 6	51	1	26	0.929	2	0.071	10	13
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	1	0
Segment:	1	0	0	0	0	0	0	1

9									
Segment: 10	7	0.6	5	0.5	1	0.1	1	0	
Totals:	313	6.4	172	5.997	13	0.403	58	70	

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		None	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		None	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
3	Manitoba Hydro	Mike Smith		None	N/A

1	Bonneville Power Administration	Kammy Rogers-Holliday	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
3	JEA	Garry Baker	None	N/A
3	Portland General Electric Co.	Dan Zollner	Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers	Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin	None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant	Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz	Abstain	N/A
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	N/A
6	Westar Energy	Grant Wilkerson	None	N/A
3	Westar Energy	Bryan Taggart	None	N/A
5	Nebraska Public Power District	Ronald Bender	Abstain	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy	Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Abstain	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall	Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan	Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen	Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	N/A
2	California ISO	Jamie Johnson	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Abstain	N/A
1	Cleco Corporation	John Lindsey	Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell	Negative	Comments Submitted
5	Austin Energy	Michael Dillard	None	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted

6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle Longo		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A

4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		None	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A

5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
3	Platte River Power Authority	Wade Kiess		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Salt River Project	Bobby Olsen		None	N/A

4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Abstain	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A

5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Evergy	Thomas ROBBEN		Affirmative	N/A
1	Evergy	Allen Klassen		Affirmative	N/A
3	Evergy	Marcus Moor		Affirmative	N/A
5	Evergy	Derek Brown		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

[redacted]

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17
45-day formal comment period with additional ballot	08/24/18-10/17/18
45-day formal comment period with additional ballot	6/19/20 - 8/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~

~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~

~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~

~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Proposed New Term

System Voltage Limit:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

A. Introduction

Title: **System Operating Limits Methodology for the Operations Horizon**

Number: FAC-011-4

Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

1.1. Functional Entities:

4.1.1. Reliability Coordinator

Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology.

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology, that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the minimum allowable System Voltage Limit;

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1 IROL exceedances;

7.1.2 SOL exceedances of stability limits;

7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.
R4.	The Reliability Coordinator failed to incorporate one of	The Reliability Coordinator failed to incorporate two of	The Reliability Coordinator failed to incorporate three of	The Reliability Coordinator failed to incorporate four or

Requirement	Lower	Moderate	High	Severe
	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	the Parts of Requirement R4 into its SOL methodology.	more of the Parts of Requirement R4 into its SOL methodology.
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be

Requirement	Lower	Moderate	High	Severe
		include one of the Parts 7.2.1 through 7.2.2.	include one of the Parts 7.1.1 through 7.1.5.	communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9,

Requirement	Lower	Moderate	High	Severe
	Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	

4	TBD	Adopted by the NERC Board of Trustees	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17
45-day formal comment period with additional ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	6/19/20 - 8/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation~~

~~within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Proposed New Term

System Voltage Limit:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology.

R2. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology, that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- **3.1.** Require that each BES bus/station have an associated System Voltage Limits, unless ~~the Reliability Coordinators~~its SOL ~~M~~methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
- **3.2.** Require that System Voltage Limits respect voltage-based Facility Ratings;
- **3.3.** Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the ~~lowest~~ minimum allowable System Voltage Limit;

3.5. ~~Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and provide~~ Define the method for determining ~~the~~ common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection. ~~to be used in operations;~~

~~**3.6.** Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and~~

~~**3.7.** Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.~~

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~unit~~ angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator ~~.~~Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion ~~extent~~modeled of the Reliability Coordinator Area, ~~as well as~~ and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)~~ for the area under study~~. The SOL ~~M~~methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events~~ for use in determining stability limits and performing OPAs and RTAs~~:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block~~, with Normal Clearing,~~ in a monopolar or bipolar high voltage direct current system.

5.2. ~~Identify any~~Specify additional single or multiple Contingency events or types of Contingency events, if any~~ for use in performing Operational Planning Analysis and Real-time Assessments~~.

~~**5.3.** Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.~~

~~**5.4.**~~**5.3.** Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-01~~5~~4-~~1~~3, Requirement R~~48~~7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. ~~The actual pre-~~System performance for no Contingenc~~y~~ies ~~state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following:

6.1.1. Steady state ~~F~~flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state ~~V~~voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded-.~~Instability, Cascading or uncontrolled separation do not occur.~~

~~**6.1.3.**~~**6.1.4.** Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric~~e~~ System does not occur.[1]

6.2. ~~The evaluation of potential~~System performance for the single Contingencies listed in Part 5.1~~.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following:

6.2.1. Steady state post-Contingency ~~F~~flow through Facilities ~~are~~ within applicable Emergency Ratings.~~, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings.~~ Steady state post-Contingency ~~F~~flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency ~~V~~voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria~~e~~ defined in the Reliability Coordinator's SOL methodology are met[1]. ~~Instability, Cascading or uncontrolled separation do not occur.~~

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

~~6.2.3.~~**6.2.4.** Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric~~e~~ System does not occur[1].

6.3. ~~The evaluation of~~ System performance for applicable ~~the potential~~ Contingencies identified in Part 5.2 ~~against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System- does not occur.

~~**6.4.** The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.~~

~~6.5.~~**6.4.** In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances;

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4. Pre-Contingency SOL exceedances of Facility Ratings; and

7.1.5. Pre-Contingency SOL exceedances of normal ~~low~~minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2. Pre-Contingency SOL exceedances of normal ~~high~~maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement R7.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL ~~M~~methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~7.1.~~8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~7.2.~~8.2. Criteria for determining when ~~violating~~ exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.

~~M7.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL ~~M~~methodology that addresses the items listed in Requirement ~~R6~~R8.

~~**R8.** Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator. The method shall address the periodicity for communicating established SOLs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M8.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.~~

R9. Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL ~~m~~~~M~~methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence ~~that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8~~ may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a documented SOL ~~M~~methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	N/A	N/A	The Reliability Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine which ~~the applicable~~ owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine which ~~the applicable~~ owner-provided Facility Ratings are to be used in operations.
R3.	The Reliability Coordinator failed to incorporate one of	The Reliability Coordinator failed to incorporate two of	The Reliability Coordinator failed to incorporate three of the Parts of Requirement	The Reliability Coordinator failed to incorporate four or more of the Parts of

	the Parts of Requirement R3 into its SOL ~~M~~methodology.	the Parts of Requirement R3 into its SOL ~~M~~methodology.	R3 into its SOL ~~M~~methodology.	Requirement R3 into its SOL ~~M~~methodology.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL ~~M~~methodology.
R5.	N/A	N/A~~The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.~~	The Reliability Coordinator failed to incorporate ~~two~~ one of the Parts 5.2 ~~, 5.3,~~ or 5.~~4~~ 3 of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL ~~M~~methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2~~, 5.3,~~ and 5.~~4~~ 3 of Requirement R5 into its SOL ~~M~~methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL ~~M~~methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances identified as part of Real-	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining how SOL exceedances	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining how SOL exceedances

		time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.2.1 through 7.2.2.	identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.1.1 through 7.1.5.	identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.
R~~7~~8.	N/A	N/A	The Reliability Coordinator failed to include Part ~~7~~8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL m~~M~~ethodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (criteria for developing any associated IROL T_v) in its SOL ~~M~~methodology.	The Reliability Coordinator failed to include Parts ~~7~~8.1 and ~~7~~8.2 in its SOL ~~M~~methodology.

~~R8.~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.~~	~~The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.~~
R9.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance

				with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	
4	TBD	Adopted by the NERC Board of Trustees	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with initial ballot	09/29/17 – 11/14/17
45-day formal comment period with additional ballot	08/24/18-10/17/18
45-day formal comment period with additional ballot	6/19/20 - 8/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Proposed New Term

System Voltage Limit:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

A. Introduction

Title: **System Operating Limits Methodology for the Operations Horizon**

Number: FAC-011-4~~3~~

Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

Applicability:

1.1. Functional Entities:

4.1.1. Reliability Coordinator

Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. ~~The~~ Each Reliability Coordinator shall have a documented methodology for ~~use in~~establishing ~~developing~~ SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area. ~~This SOL Methodology shall:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

~~**1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.~~

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its ~~The Reliability Coordinator's~~ SOL ~~M~~methodology~~ shall address all of the items listed in Requirement 1 through Requirement 3~~.

R2. ~~The~~ Each Reliability Coordinator~~'s~~ shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings ~~shall include a requirement that SOLs provide BES performance consistent with the following:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**2.1.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.~~

~~**2.2.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

~~**1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.~~

~~**2.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

~~**3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.~~

~~**2.3.** In determining the system's response to a single Contingency, the following shall be acceptable:~~

~~**1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**3.** System reconfiguration through manual or automatic control or protection actions.~~

~~**2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its ~~The Reliability Coordinator shall have evidence it issued its~~ SOL ~~M~~methodology, that addresses the items listed in Requirement R2~~and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.~~

R3. ~~The~~ Each Reliability Coordinator~~'s~~ shall include in its SOL methodology ~~method~~the methodology ~~ology~~ for Transmission Operators to determin~~e~~ing the System Voltage Limits to be used in operations. The method shall: ~~SOLs, shall include, as a minimum, a~~

~~[1] The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~description of the following, along with any reliability margins applied for each:~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;~~Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;~~Selection of applicable Contingencies~~

3.3. Require that System Voltage Limits are greater than or equal to in-service BES relay settings for undervoltage load shedding systems and Undervoltage Load Shedding Programs;~~A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.~~

~~**1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

3.4. Identify the minimum allowable System Voltage Limit;~~Level of detail of system models used to determine SOLs.~~

3.5. Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection~~Allowed uses of Remedial Action Schemes~~.

~~**3.6.** Anticipated transmission system configuration, generation dispatch and Load level~~

~~**3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.~~

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R3.

R4. ~~The~~ Each Reliability Coordinator shall include in ~~issue~~ its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:~~

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:~~Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.~~

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

~~4.1.~~4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its~~Each Planning Authority and Transmission Planner that models any~~ portion of ~~the Reliability Coordinator's Reliability Coordinator Area~~the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one~~Each~~ Transmission Operator in its Reliability Coordinator Area or other ~~that operates in the~~ Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages.

4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following single Contingency events

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1 IROL exceedances;

7.1.2 SOL exceedances of stability limits;

7.1.3 Post Contingency SOL exceedances that are identified to have a validated risk of instability, Cascading, and uncontrolled separation;

7.1.4 Pre-Contingency SOL exceedances of Facility Ratings; and

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

7.1.5 Pre-Contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1 Post-Contingency SOL exceedances of Facility Ratings and emergency System Voltage Limits, and

7.2.2 Pre-Contingency SOL exceedances of normal maximum System Voltage Limits.

M7. Acceptable evidence may include, but is not limited to dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall include in its SOL methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_V.

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL methodology that addresses the items listed in Requirement R8.

R9. Each Reliability Coordinator shall provide its SOL methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and -indicated it had a reliability-related need.

M9. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

~~**M1.**~~

~~M2.~~M1. ~~The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~M3.~~M1. ~~The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.~~

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 for the current year plus the previous 12 calendar months.

   1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1.	N/A~~Not applicable.~~	N/A~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~	N/A~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~did not have a documented SOL ~~M~~methodology for ~~use in developing~~ establishing SOLs within its Reliability Coordinator Area~~, but it does not address R1.1~~. ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.~~
R2.	N/A~~The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~	N/A~~Not applicable.~~	The Reliability ~~Coordinator's~~Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations, but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators	The Reliability Coordinator~~'s~~ did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations.~~does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single~~

Requirement	Lower	Moderate	High	Severe
			in its Reliability Coordinator Area.~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~	~~contingencies. (R2.1 through R2.4)~~
R3.	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate two of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability Coordinator~~'s~~ failed to incorporate four or more of the Parts of Requirement R3 into its SOL ~~M~~methodology ~~is missing a description of four or more of the following: R3.1 through R3.7~~.
R4.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into~~issue~~ its SOL ~~M~~methodology ~~and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3~~. ~~OR~~

Requirement	Lower	Moderate	High	Severe
	~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to30 days after the effectiveness of the change.~~	~~For a change in methodology, the changed methodology was provided to one or more of the required entities more than30 calendar days after the effectiveness of the change.~~
R5.	N/A	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2 or 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2 and 5.3 of Requirement R5 into its SOL methodology.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.
R7.	N/A	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining	The Reliability Coordinator included in its SOL methodology, a risk-based approach for determining	The Reliability Coordinator failed to include in its SOL methodology, a risk-based approach for determining

Requirement	Lower	Moderate	High	Severe
		how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.2.1 through 7.2.2.	how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority, but failed to include one of the Parts 7.1.1 through 7.1.5.	how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.
R8.	N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.

Requirement	Lower	Moderate	High	Severe
R9.	The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to

Requirement	Lower	Moderate	High	Severe
				a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1.

D. Regional Variances

~~1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:~~

~~1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:~~

~~1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.~~

~~1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7~~

~~1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.~~

~~1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.~~

~~1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.~~

~~1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.~~

~~1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.~~

~~1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:~~

~~1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.~~

~~1.2.2 Cascading does not occur.~~

~~1.2.3 Uncontrolled separation of the system does not occur.~~

~~1.2.4 The system demonstrates transient, dynamic and voltage stability.~~

~~1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~1.3.1 Cascading does not occur.~~

~~1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

~~None.~~Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.	

4	TBD	Adopted by the NERC Board of Trustees	Revised

~~Standard Attachments~~

~~(DELETE GREEN TEXT PRIOR TO PUBLISHING) NOTE: Use this section for attachments or other documents (Interpretations, etc.) that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.~~

~~[Title of document]~~

~~(DELETE GREEN TEXT PRIOR TO PUBLISHING) Documents that should appear in this section are as follows: Application Guidelines, Training Material, Reference Material and/or other Supplemental Material. The header should remain "Supplemental Material."~~

~~Text, text, text~~

~~Text, text, text~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20
45-day formal comment period with additional ballot	10/23/20 – 12/07/20
45-day formal comment period with additional ballot	02/19/21 - 04/05/21

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL methodology”).
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective

			limiting Facility Ratings, System Voltage Limits or stability criteria	Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission

			Owner, and Generation Owner, but failed to provide them annually.	Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Adopted by Board of Trustees	Revised

Standard Development Timeline

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10-day final ballot	April 2021
NERC Board adoption	May 2021

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4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.

R3. Each Transmission Operator shall provide its SOLs to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.

R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL methodology”) ~~as established in FAC-011-4~~.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			such information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability

			provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria	described in its respective Reliability Coordinator's SOL methodology.
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed

			in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Adopted by Board of Trustees	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16
45-day formal comment period with ballot	09/29/17 – 11/14/17
45-day formal comment period with ballot	08/24/19 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20
45-day formal comment period with additional ballot	10/23/20 – 12/07/20
45-day formal comment period with additional ballot	02/19/21 - 04/05/21

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-~~2~~3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable ~~planning and~~ operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.
4. **Applicability**

   4.1. Functional Entities

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

   4.1.4. Transmission Planner

5. **Effective Date:** ~~April 29, 2009~~See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. ~~The~~ Each Reliability Coordinator shall establish ~~ensure that SOLs, including~~ Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*~~for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology~~

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it SOL methodology.~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

R2. ~~The~~ Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the ~~(as directed by its~~ Reliability Coordinator~~)~~ Area in accordance with ~~for~~ its ~~portion of the~~ Reliability Coordinator's ~~Area that are consistent with its Reliability Coordinator's~~ SOL ~~M~~methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL methodology.~~The Reliability~~

~~Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

R3. ~~The~~ Each ~~Planning Authority~~Transmission Operator shall provide its ~~establish~~ SOLs~~,~~ to its Reliability ~~Coordinator~~ Coordinator ~~including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs.~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.~~

R4. ~~The Transmission Planner~~Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with ~~SOLs, including IROLs, for its Transmission Planning Area that are consistent with~~ its ~~Planning Authority's~~ SOL ~~M~~methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~M1.~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established stability limits in accordance with Requirement R4.

~~R3.~~R5. Each~~The~~ Reliability Coordinator~~, Planning Authority, and Transmission Planner~~ shall ~~each~~ provide ~~its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows~~: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 ~~The Reliability~~Each Planning Coordinator and each Transmission Planner within ~~shall provide~~ its ~~SOLs (including the subset of SOLs that are IROLs) to adjacent~~ Reliability Coordinator ~~s~~ Area,~~and Reliability Coordinators who indicate a reliability-related need for those limits, and to~~ the SOLs ~~Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within~~for its Reliability Coordinator Area~~.~~ ~~(including~~including the subset of SOLs that are ~~For each~~ IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*~~, the Reliability Coordinator shall provide the following supporting information:~~

5.2 ~~Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.~~

~~The value of the IROL and its associated T_v.~~

~~The associated Contingency(ies).~~

~~The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).~~

Each impacted Planning Coordinator and each impacted~~The~~ Transmission ~~Operator~~ Planner ~~shall provide any SOLs it developed to~~within its Reliability Coordinator Area,~~and to~~ the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*~~Transmission Service Providers that share its portion of the Reliability Coordinator Area.~~

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within~~The Planning Authority shall provide~~ its ~~SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and~~ Reliability Coordinator Area~~s~~, the value of the stability limits —established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*~~that work within its Planning Authority Area.~~

5.4 Each impacted~~The~~ Transmission ~~Planner~~ Operator ~~shall provide its SOLs (including the subset of SOLs that are IROLs) to~~within its ~~Planning Authority,~~ Reliability Coordinator~~s~~ Area, the information identified in —Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*~~Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

~~M2.~~M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

~~R4.~~R6. ~~The~~ Each Planning ~~Authority~~ Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

- The Planning Coordinator may ~~Authority~~ use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.~~shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~
- ~~If t~~The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and~~Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Reliability Coordinator.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner implemented its documented process in accordance with Requirement R6.

R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R7.

R8. Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

~~M3.~~M8. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R8.

~~C. Measures~~

~~**M4.M1.** The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.M1.** The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.M1.** The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.~~

~~G.~~C. Compliance

1. Compliance Monitoring Process

1.1. **Compliance Enforcement Authority:**~~**Compliance Monitoring Responsibility**~~

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~Regional Reliability Organization~~

1.2. Evidence Retention:~~Compliance Monitoring Period and Reset Time Frame~~

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator, Transmission Operator, Transmission Planner, Planning Coordinator shall keep data or evidence of Requirements R1 through R8 for the current year plus the previous 12 calendar months.

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~1.5.~~1.3. Compliance Monitoring and Enforcement Program~~Data Retention~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~1.6. Additional Compliance Information~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~1.6.1~~ ~~SOL Methodology(ies)~~

~~1.6.2~~ ~~SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~1.6.3~~ ~~Evidence that SOLs were distributed~~

~~1.6.3~~ ~~Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~1.6.3~~ ~~Distribution schedules provided by entities that requested SOLs~~

Violation Severity Levels:

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	N/A~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	N/A~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology ("SOL methodology").~~There are SOLs for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~
R2.	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	N/A~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.~~The Transmission Operator has established SOLs for its portion of the Reliability~~

				~~Coordinator Area, but 75% or more of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~
R3.	N/A~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	N/A~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.~~There are SOLs for the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~
R4.	N/A~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	N/A~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	N/A~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~	The Reliability Coordinator failed to establish stability limits to be used in operations when the limit impacts an adjacent Reliability Coordinator or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.~~The~~

				~~Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 75% or more of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~
R6.	N/A~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~	N/A~~Not applicable.~~	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings,

			limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~	System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~
R7.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not

	contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.
R8.			The Planning Coordinator or a Transmission Planner provided the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner, but failed to provide them annually.	The Planning Coordinator or a Transmission Planner failed to provide the instability, Cascading or uncontrolled separation information listed in Requirement R8 to the applicable Transmission Owner, and Generation Owner.

~~H.~~D. Regional Variances

None.

~~I.~~E. Interpretations

None.

~~J.~~F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		**Adopted by Board of Trustees**	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 - 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[1] state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[2] state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[7]

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

M2. [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this Reliability Standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- **7.1.** Change in expected growth rate/environmental factors
- **7.2.** Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]
- **7.3.** Rescheduling work between growing seasons
- **7.4.** Crew or contractor availability/Mutual assistance agreements
- **7.5.** Identified unanticipated high priority work
- **7.6.** Weather conditions/Accessibility
- **7.7.** Permitting delays
- **7.8.** Land ownership changes/Change in land use by the landowner
- **7.9.** Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

(as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and encroachment into the MVCD as identified in FAC-003-5-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.Reserved for future use				

R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.

R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	TBD	Adopted by Board of Trustees	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[15] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[16] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[17] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1:
R1 is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines R1 requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirements R1 states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable

Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

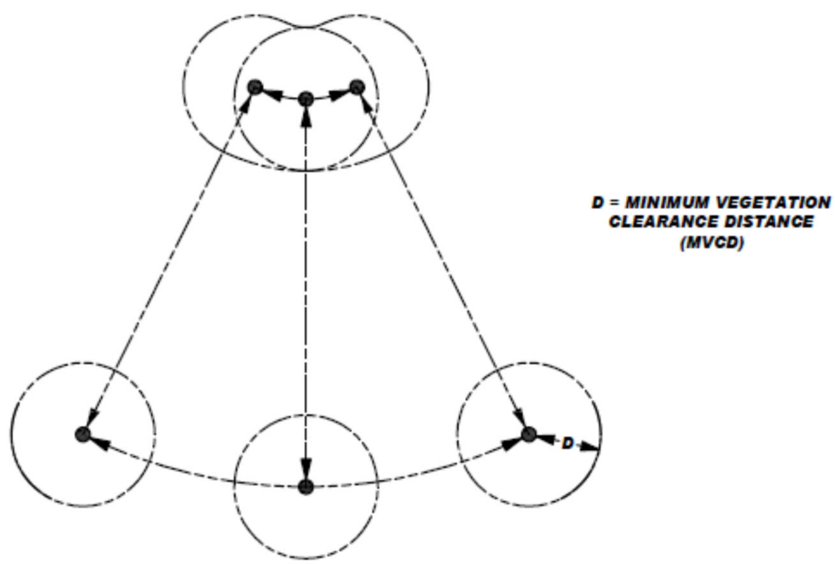

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):

Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

> *conditions (if any), shall have <u>what capability</u>, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for Reliability Standards development recognizes that each requirement in a NERC Reliability Standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability Standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a Reliability Standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use]

~~**2.0.**~~

~~**M3.**~~**M2.** [Reserved for future use]

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

~~M4.~~**M3.** The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

~~M5.~~**M4.** Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

~~M6.~~**M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

~~**M7.**~~**M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

~~**M8.**~~**M7.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, ~~R2,~~ R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote ~~2~~4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only),~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as Facility~~ies~~ that if lost or degraded are ~~epected~~expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its~~

~~Transfer Capability Assessment (Planning Coordinator only)~~ as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon ~~or its Transfer Capability Assessment (Planning Coordinator only)~~ as a Facility~~ies~~ that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path~~ blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and encroachment into the MVCD as identified in FAC-003-5-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2. Reserved for future use				

R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.

R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	TBD	Adopted by Board of Trustees	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161~~*~~	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138~~*~~	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115~~*~~	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88~~*~~	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69~~*~~	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

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15 The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

16 Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

17 The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

⁺ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV-, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No.

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1:
R1 is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines R1 requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element in the Applicability section 4.2 and 4.3.

Requirements R1 states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*

3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

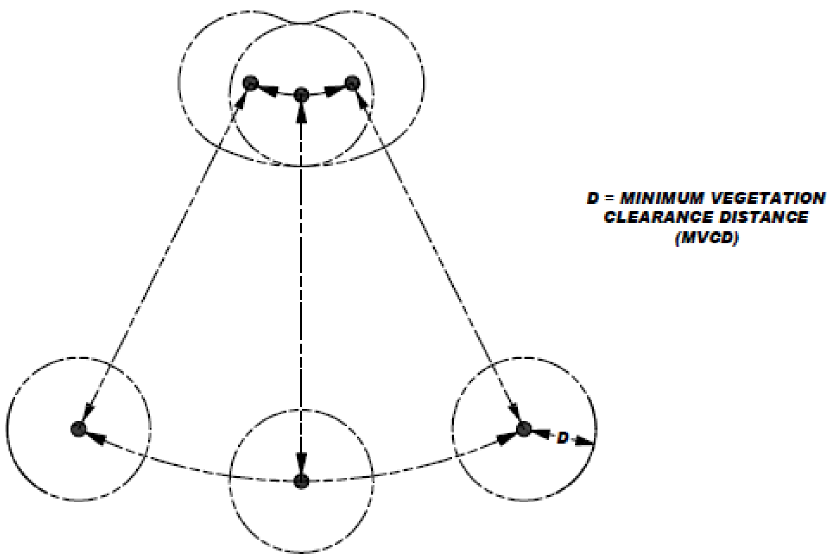

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal

rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner’s vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 - 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5~~4~~

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal,[1]~~,~~ state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

4.3. Generation Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal,[2]~~;~~ state, provincial, public, private, or tribal entities:

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner’s Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

[2] *Id.*

[3] “Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The defense-in-depth strategy for R~~r~~eliability S~~s~~tandards development recognizes that each requirement in a NERC R~~r~~eliability S~~s~~tandard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability S~~s~~tandards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a R~~r~~eliability S~~s~~tandard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Requirement R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), ~~which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all

Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[7]~~;~~

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:~~

~~**2.1.** An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]~~

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[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this R~~r~~eliability S~~s~~tandard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

~~[9] *See footnote 4.*~~

~~[10] *See footnote 5.*~~

~~[11] *See footnote 6.*~~

~~**2.2.** An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]~~

~~**2.3.** An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]~~

~~**2.4.** An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

M2. [Reserved for future use] ~~Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)~~

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

~~12. *Id.*~~

~~13. Id.~~

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

[9] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

[10] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, ~~R2,~~ R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote ~~2~~4, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System ~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~as an element of an IROL or Major WECC Transfer Path,~~ by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~as an element of~~

~~an IROL or Major WECC Transfer Path,~~ blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 ~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-45-Table 2 was observed in real time	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified in the Applicability section 4.2 and 4.3 ~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following:

			absent a Sustained Outage.	• *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2. Reserved for future use			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ ~~*A fall-in from inside the active transmission line ROW*~~ ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~

				~~A grow-in~~
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned

				vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

[11] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	
5	TBD	Adopted by Board of Trustees	Revisions

FAC-003 — Table 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)*	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

[12] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[13] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

+ Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

~~* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)~~

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15 The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

16 Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

17 The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[18] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators or Transmission Planners may designate lines below 200 kV~~-~~, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event~~, to become elements of an IROL or Major WECC Transfer Path~~ in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event ~~as an element of an IROL or Major WECC Transfer Path~~ may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an ~~IROL~~ identified element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the ~~S~~standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation

coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1~~ and R2~~:

R1 ~~and R2 are~~is a performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines~~. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both~~ R1 ~~and R2~~ requires each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer~~ in the Applicability section 4.2 and 4.3~~Pathby the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~. ~~R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separationpursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths.~~

~~The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separationthat is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Pathshave not been identified as such. Applicable lines that are not elements of IROLs or Major WECC Transfer Pathshave not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.~~

Requirements R1 ~~and R2~~ states that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 ~~and R2~~ are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

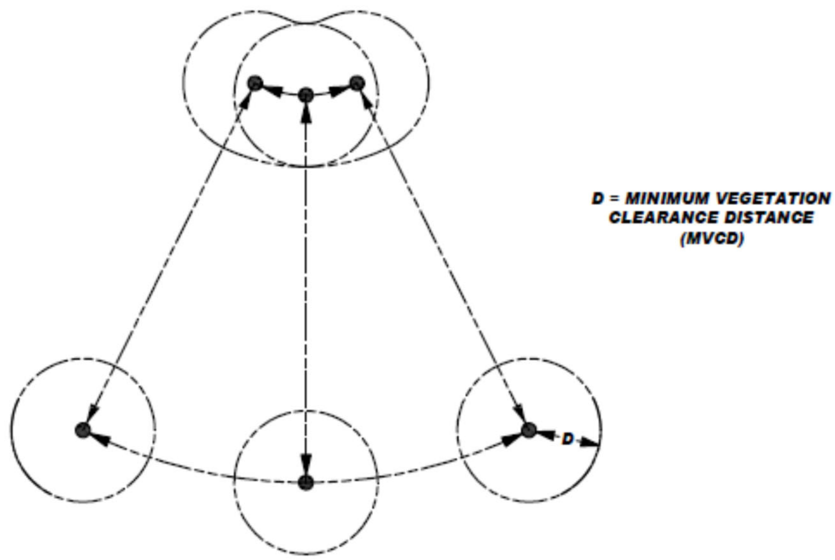

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	**(AC) Max System Voltage (kV)**	**Transient Over-voltage Factor (T)**	**Clearance (ft.) Gallet (wet) @ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003 MAID (ft) @ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1~~ and R2~~:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner’s vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

    Functional Entities:

    4.1 Reliability Coordinator

    4.2 Transmission Owner

    4.3 Generator Owner

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	Revised

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-3 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this

determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing

filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner
5. **Effective Date~~s~~:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~2~~3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~2~~3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or

NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	Revised

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

High Level Requirement Overview

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-~~2~~3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a -10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-~~2~~3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-~~2~~3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-~~2~~3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-~~2~~3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-~~2~~3 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.
Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-~~2~~3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-~~2~~ 3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-3~~2~~
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator**~~

~~**4.1.3** Western Interconnection – Reliability Coordinator~~

~~**4.1.4** Quebec Interconnection – Planning Coordinator or Reliability Coordinator~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~2~~3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~2~~3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner,~~ Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	Revised

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC | ~~RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-~~2~~3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners

across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of

selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-~~2~~ 3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-~~2~~ 3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-~~2~~ 3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-~~2~~ 3 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those

thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the

contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-~~2~~ 3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be

expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its

initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~3~~2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator**~~

~~4.1.3 Western Interconnection – Reliability Coordinator~~

~~4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~2~~3, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~2~~3, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, ~~Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	TBD	Adopted by NERC Board of Trustees	Revised

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC |~~ RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-~~2~~3, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners

across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of

selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a ~~-~~10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-~~2~~ 3 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-~~2~~ 3 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-~~2~~ 3 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-~~2~~ 3 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those

thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the

contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-~~2~~ 3 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-~~2~~ 3are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10:

Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be

expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its

initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18
45-day formal comment period with additional ballot	6/19/20 – 8/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-5
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~4~~ 5 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation ~~Plan for the Revised Definition of "Remedial Action Scheme"~~.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~4~~5 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~4~~5, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below

unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the

Requirement	Lower	Moderate	High	Severe
				loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line

Requirement	Lower	Moderate	High	Severe
				relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR

Requirement	Lower	Moderate	High	Severe
		months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning	more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process

Requirement	Lower	Moderate	High	Severe
		Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)		described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR

Requirement	Lower	Moderate	High	Severe
				The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

Version	Date	Action	Change Tracking
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	TBD	Adopted by the NERC Board of Trustees	

PRC-023-45 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).
- **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

- **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications except as noted in section 1.6.
- **2.2.** Protection systems intended for the detection of ground fault conditions.
- **2.3.** Protection systems intended for protection during stable power swings.
- **2.4.** Not used.
- **2.5.** Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
- **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
- **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **2.8.** Relay elements associated with dc lines.
- **2.9.** Relay elements associated with dc converter transformers.

PRC-023-45 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	8/24/18 – 10/17/18
45-day formal comment period with additional ballot	6/19/20 – 8/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-54

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-45 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used

exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: ~~:~~ See Implementation ~~Plan for (?)~~~~See Implementation Plan for the Revised Definition of "Remedial Action Scheme"~~.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
    a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~4~~5 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~4~~5, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-~~4~~5, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	TBD	Adopted by the NERC Board of Trustees	

PRC-023-45 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).
- **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

- **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications except as noted in section 1.6.
- **2.2.** Protection systems intended for the detection of ground fault conditions.
- **2.3.** Protection systems intended for protection during stable power swings.
- **2.4.** Not used.
- **2.5.** Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
- **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
- **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **2.8.** Relay elements associated with dc lines.
- **2.9.** Relay elements associated with dc converter transformers.

PRC-023-45 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

~~**B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates: See Implementation Plan

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event..
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	TBD	Adopted by NERC Board of Trustees	Revised

PRC-026-2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-2 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-2 – Attachment B.

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[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to any generating output limitation or RAS. A stability constraint limits the output of the portion of the

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[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay’s susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1)
$$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

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[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

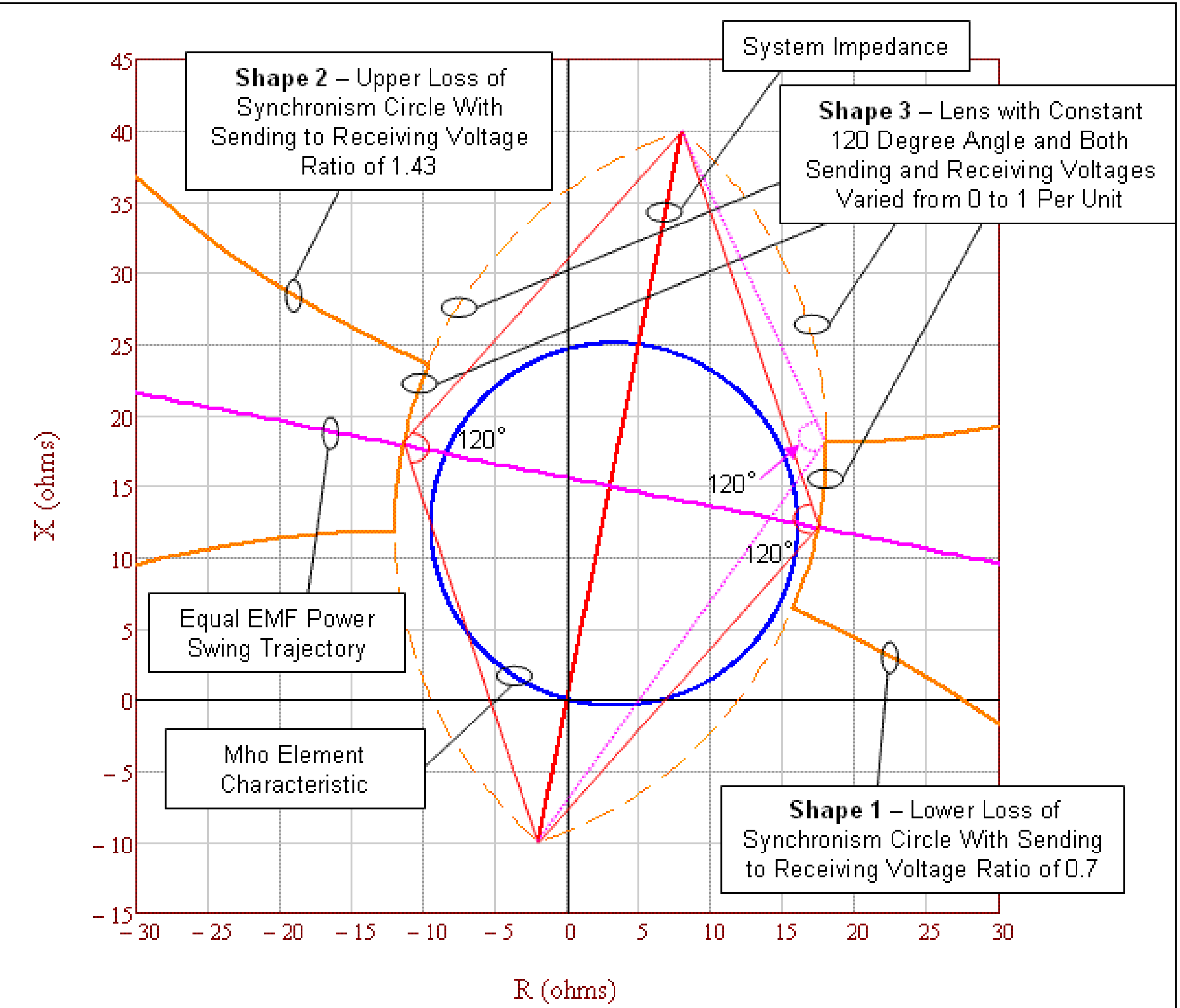


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-2 – Attachment B, Criterion A, No. 1.

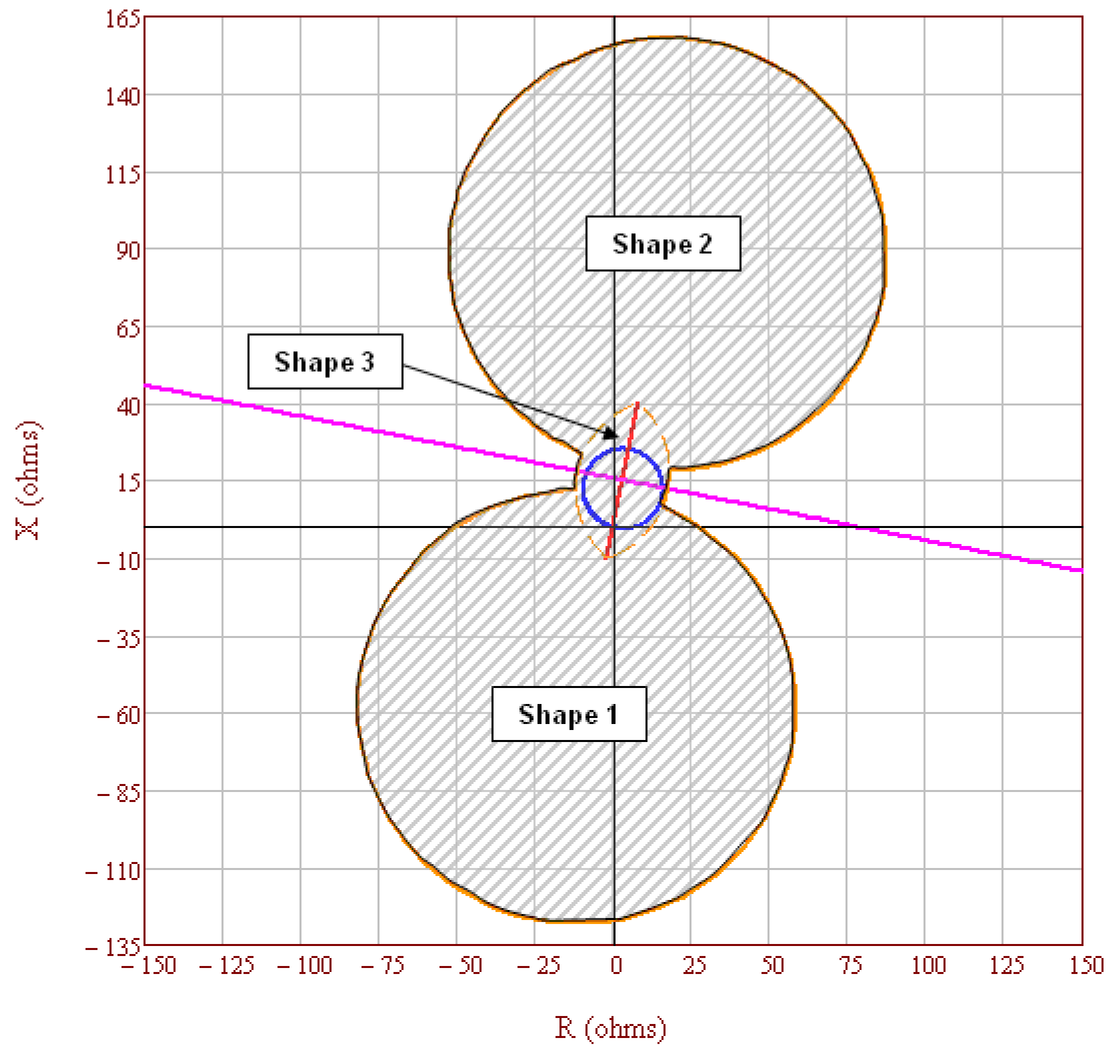


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

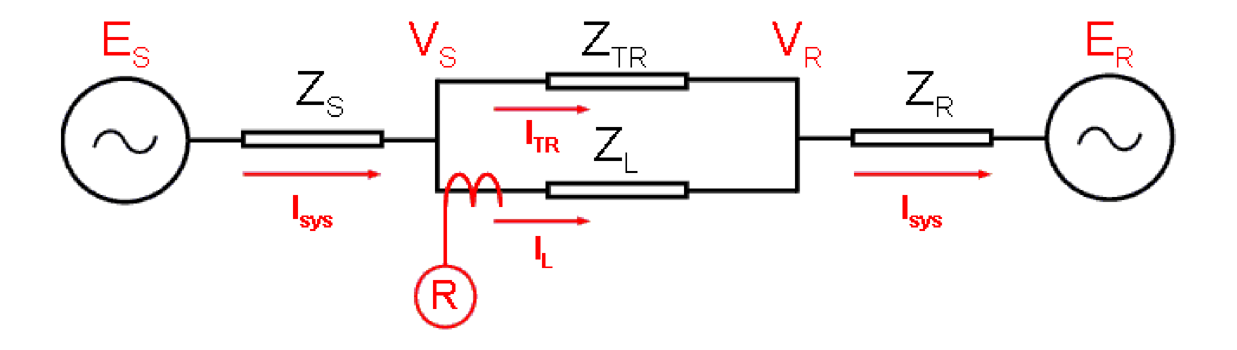


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

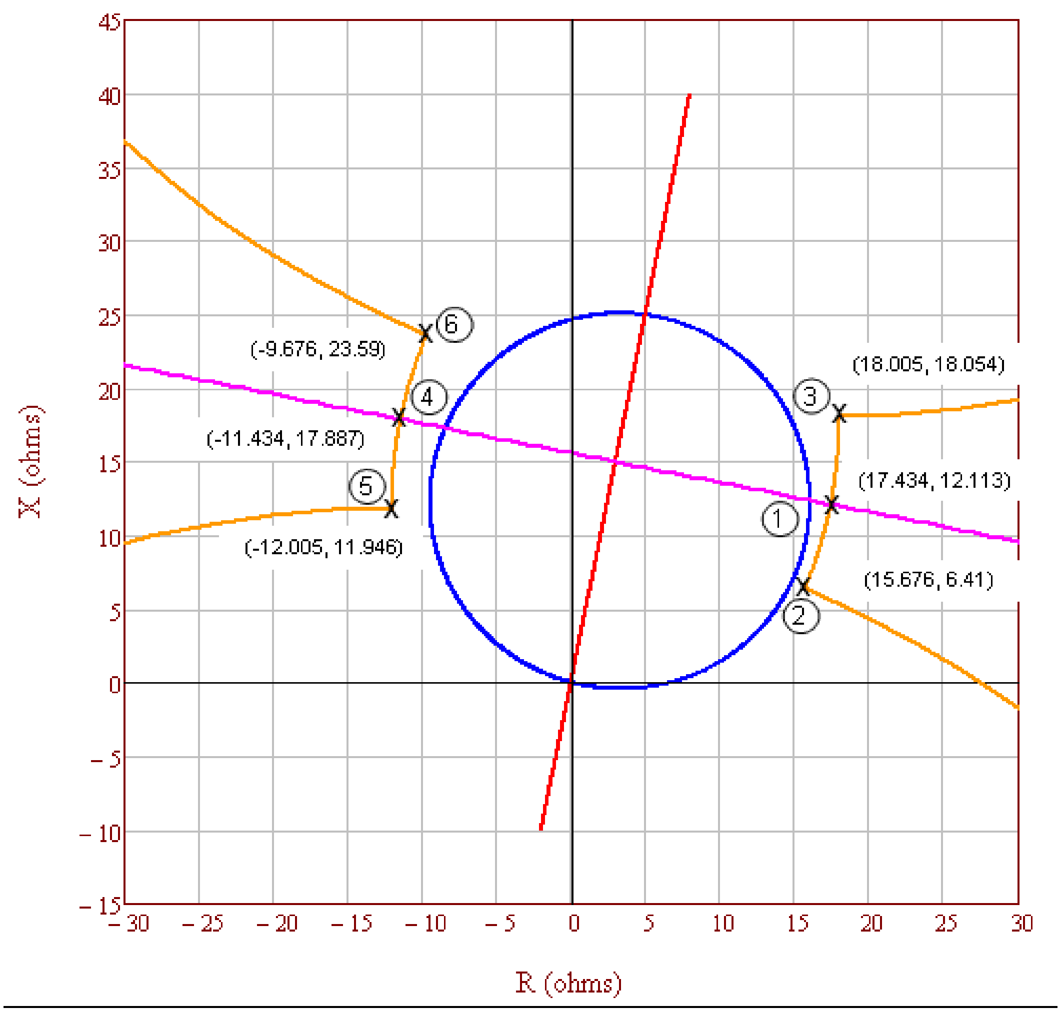


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10+j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2+j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

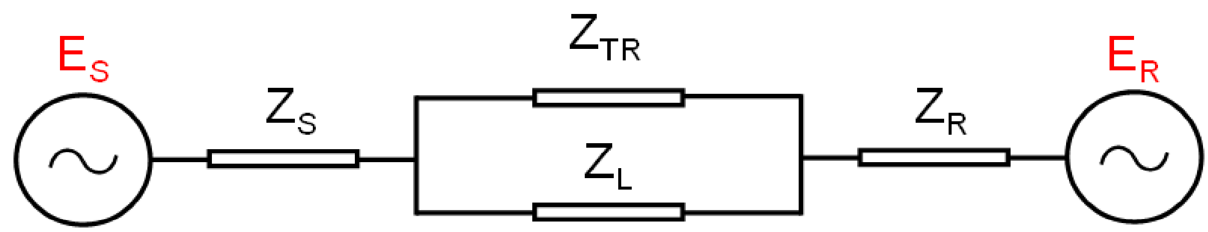
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}511\angle 131.1°\ A]$
	$V_S = 95{,}756\angle -106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle -106.1°\ V}{4{,}511\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

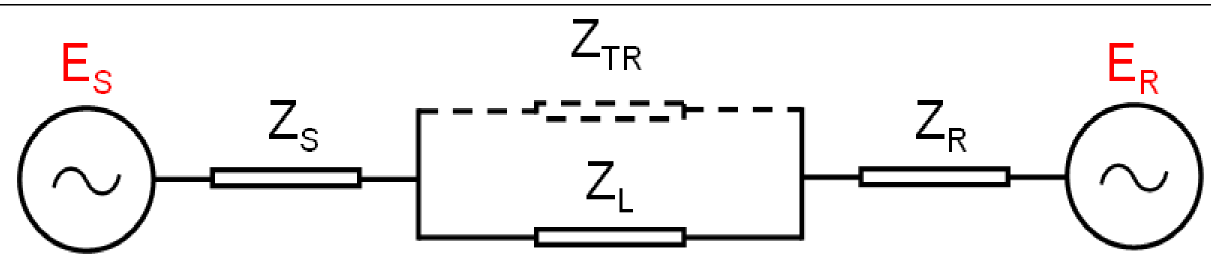
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle - 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle - 110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

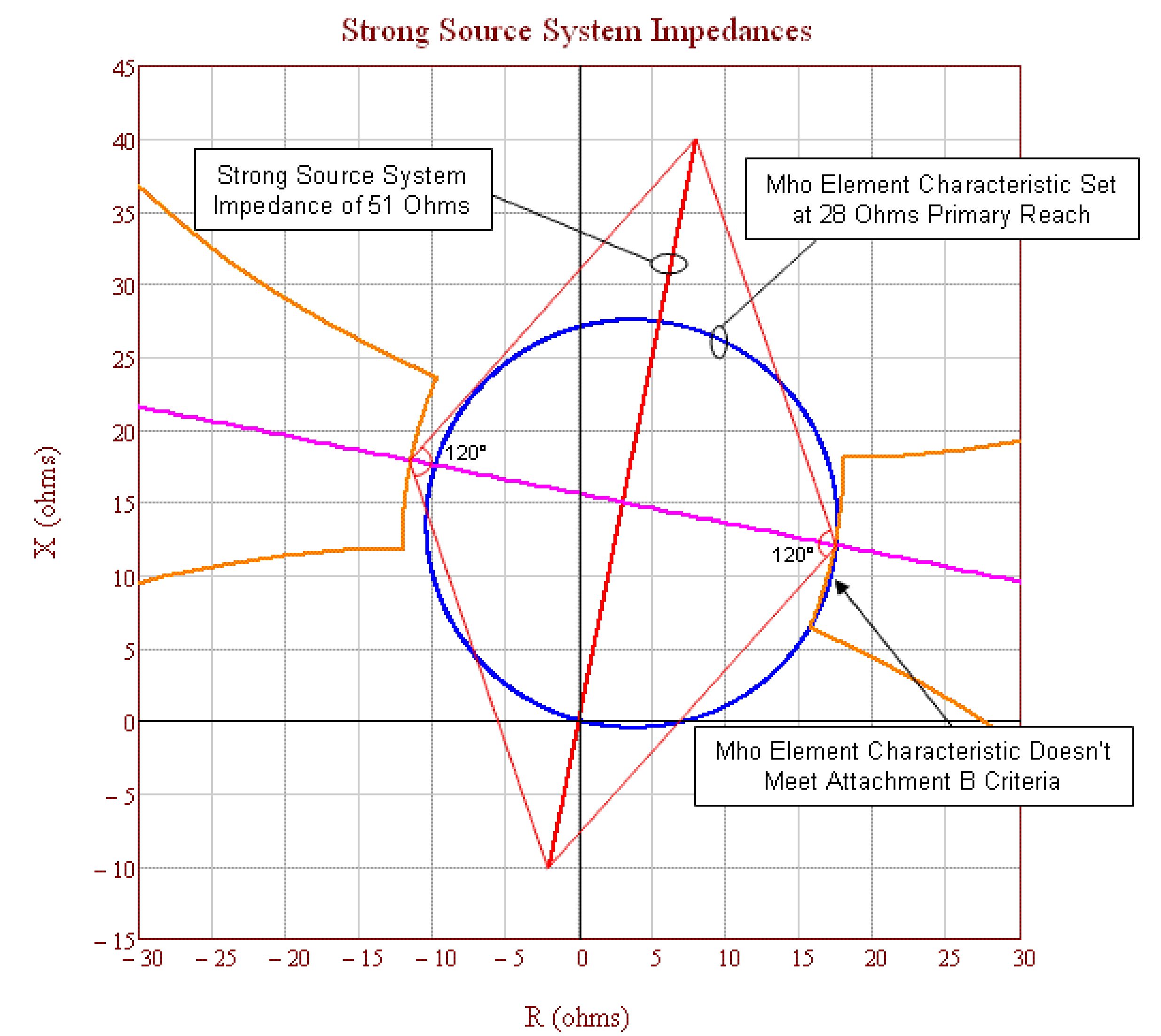


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

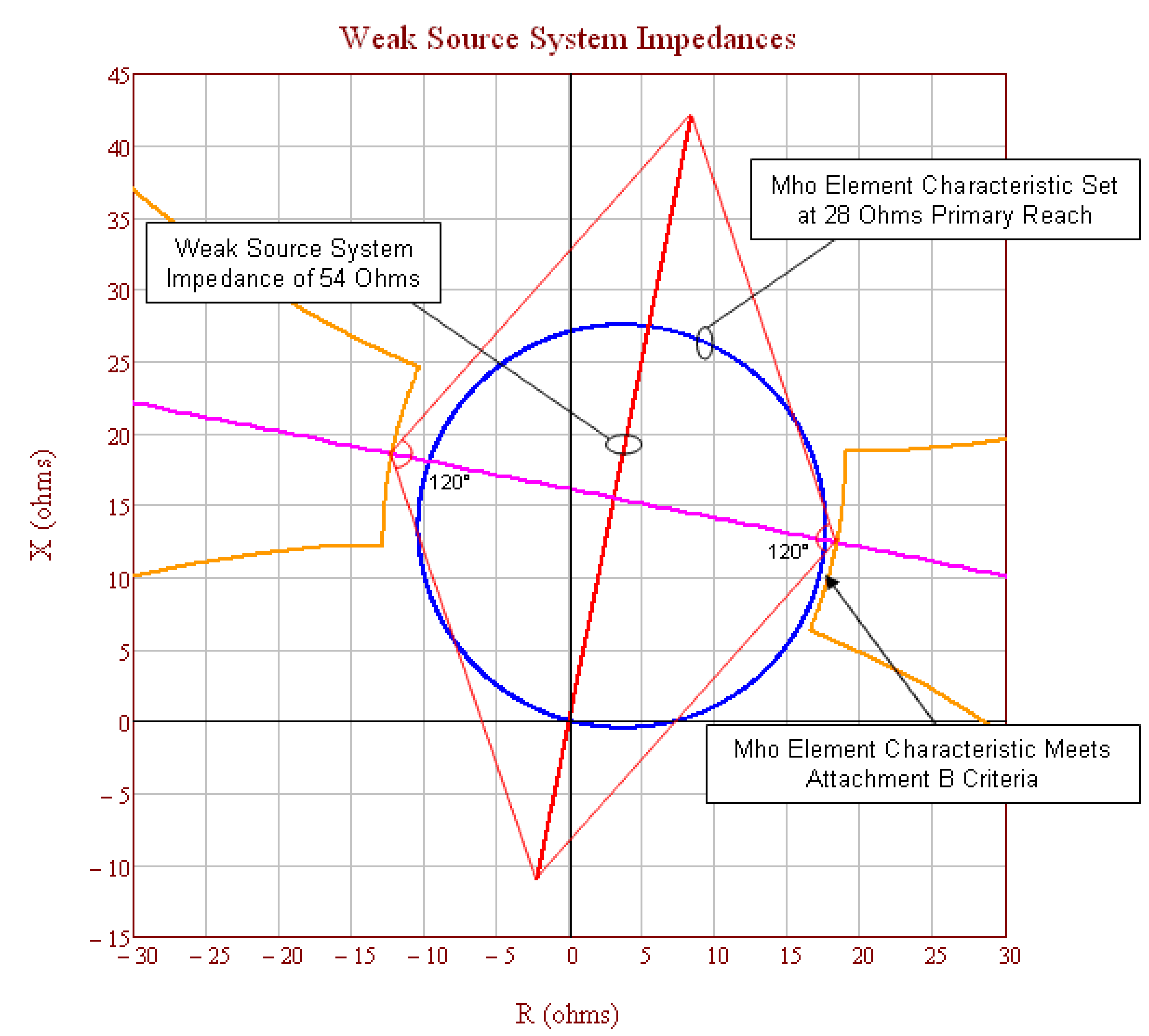


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

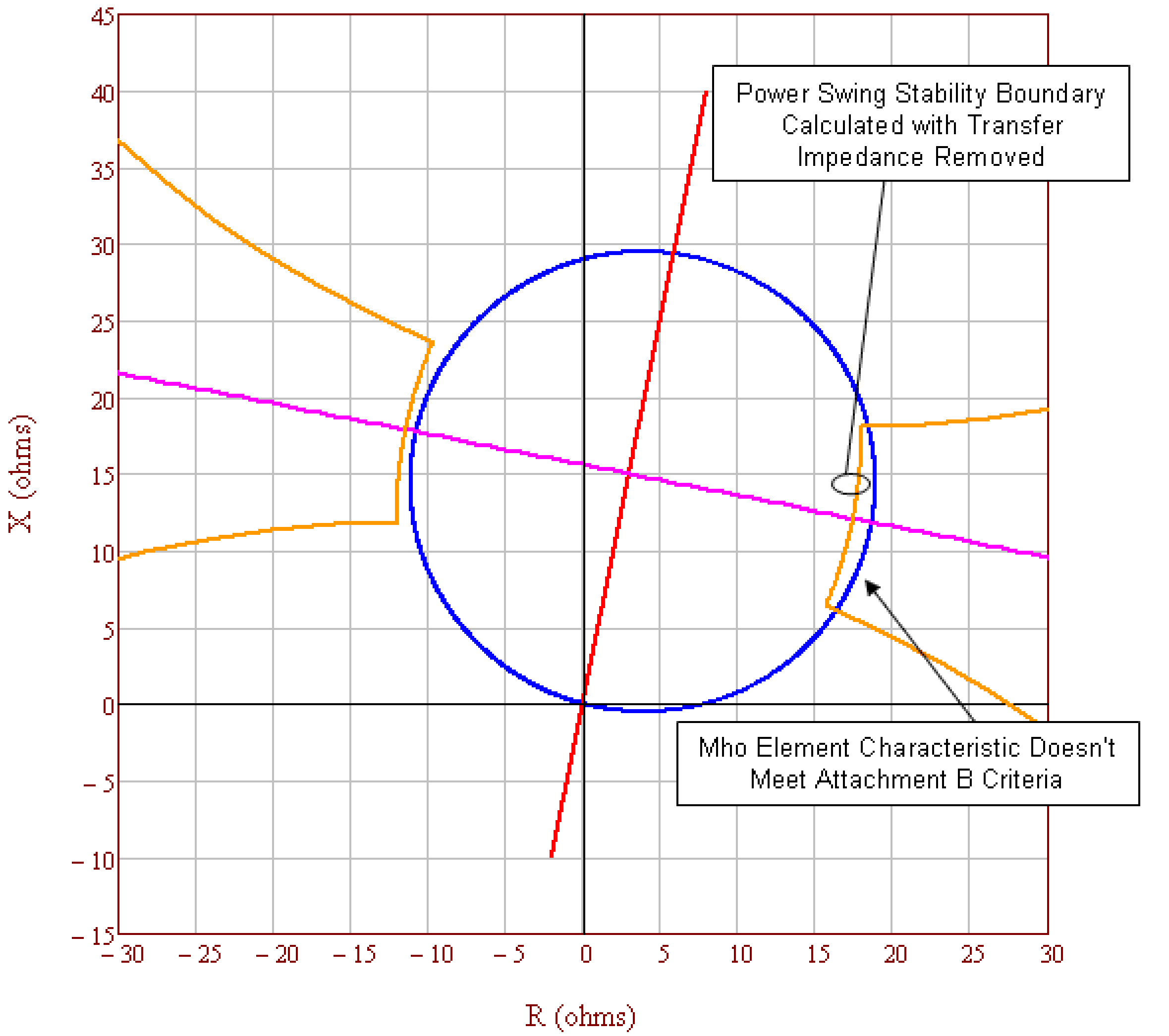


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\, A]$
	$V_S = 95{,}757\angle 106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\, V}{4{,}511\angle 71.3°\, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

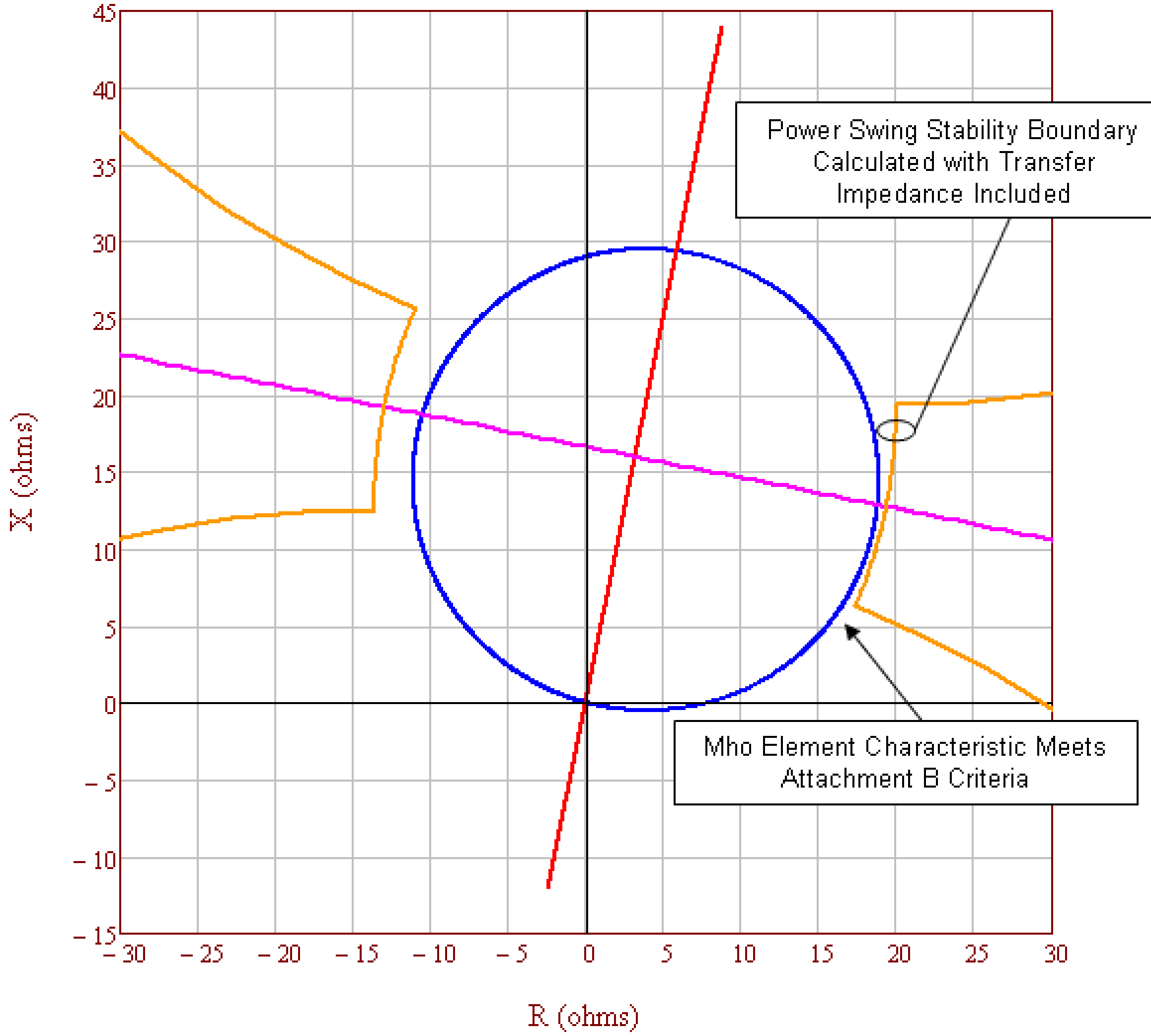


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

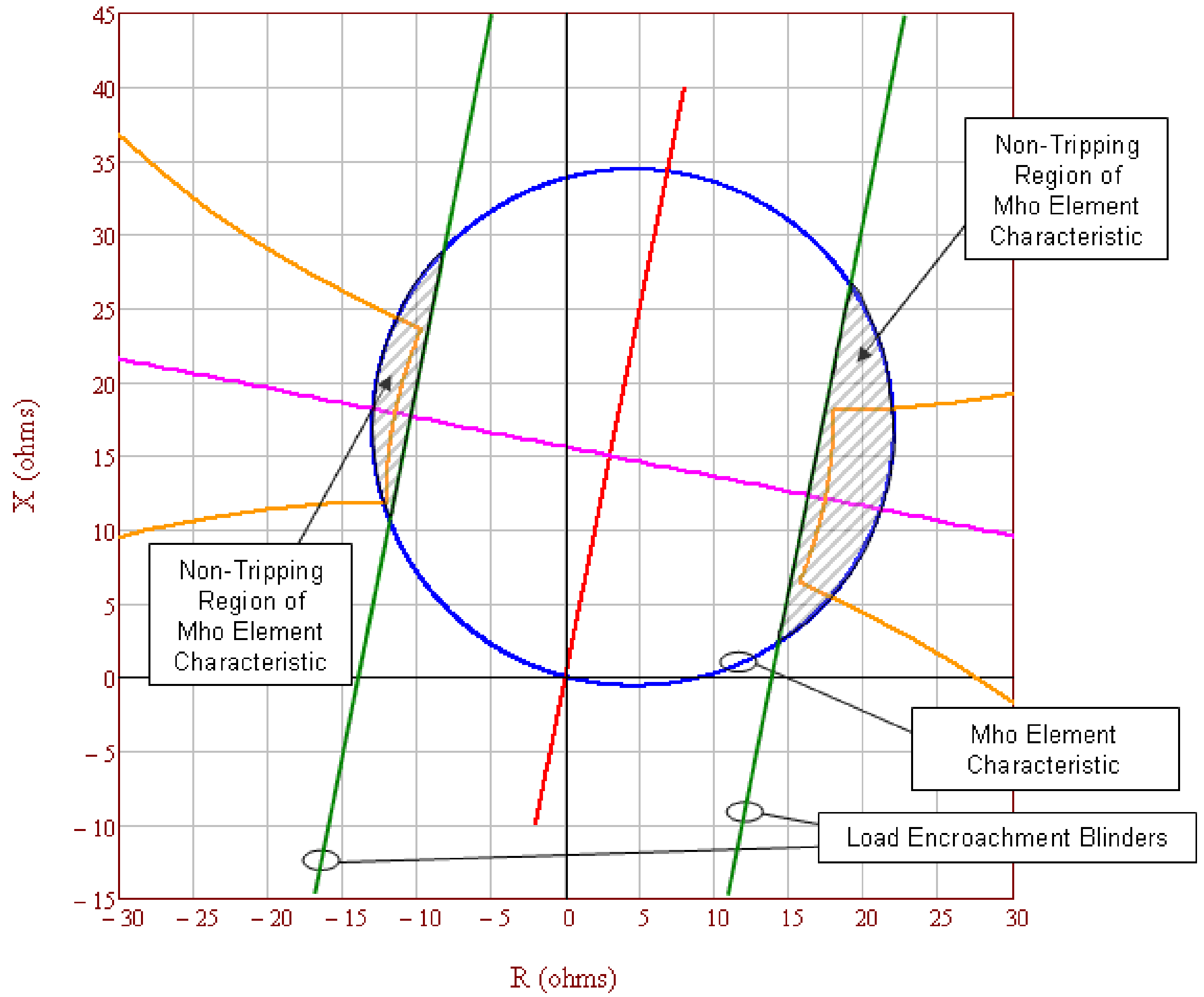


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-2– Attachment B, Criterion A.

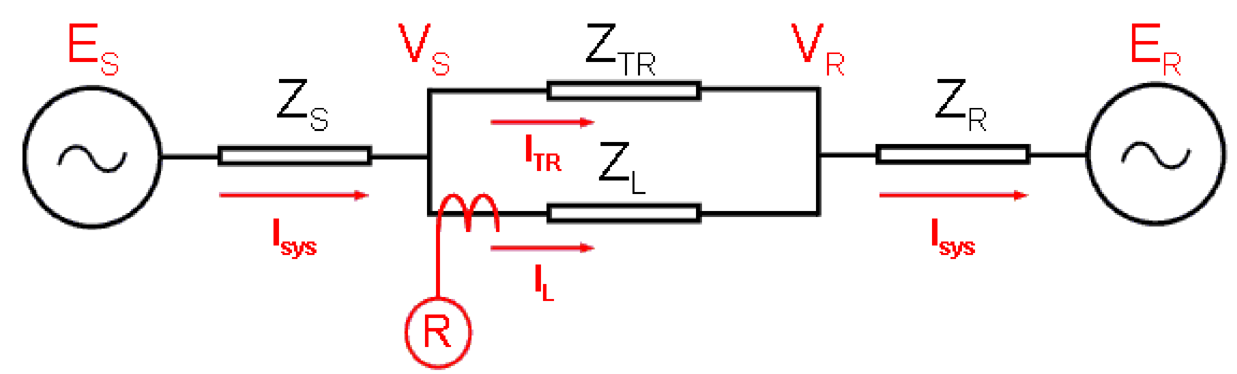


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

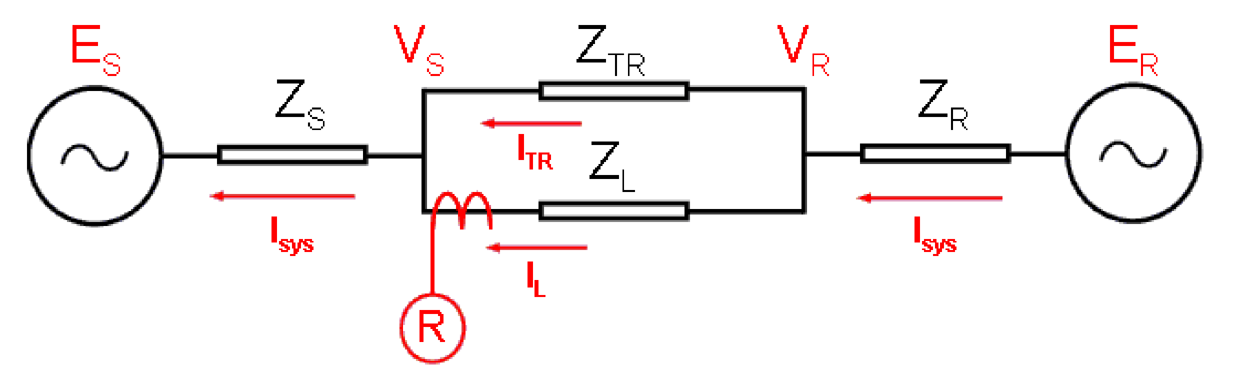


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \dfrac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \dfrac{V_R}{I_L} = Z_L + Z_S + \dfrac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\dfrac{I_{TR}}{I_L} = \dfrac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

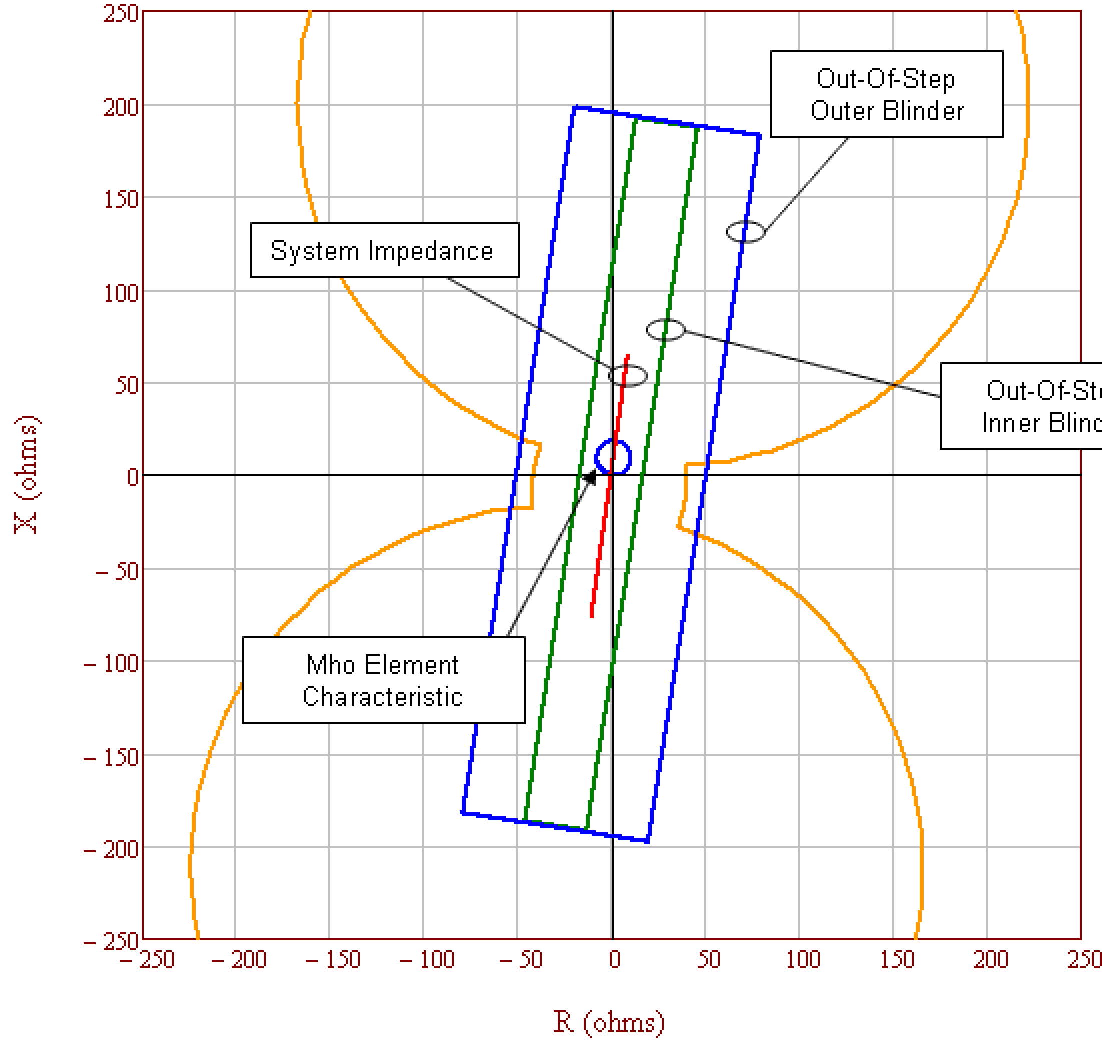


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)		
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.		
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.		
Given:	$E_S = 0.7$	$E_R = 1.0$
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$	
The total system impedance as seen by the relay with infeed formulae applied.		
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$; $Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$	
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$	
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$	
	$Z_{sys} = 10 + j50\ \Omega$	
The calculated coordinates of the lower loss-of-synchronism circle center.		
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$	
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$	
	$Z_{C1} = -11.608 - j58.039\ \Omega$	
The calculated radius of the lower loss-of-synchronism circle.		
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$	
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$	
	$r_a = 69.987\ \Omega$	
The calculated coordinates of the upper loss-of-synchronism circle center.		
Given:	$E_S = 1.0$	$E_R = 0.7$

17 http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[\ (4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert\frac{N \times Z_{sys}}{N^2 - 1}\right\rvert$
	$r_b = \left\lvert\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right\rvert$
	$r_b = 69.987\ \Omega$

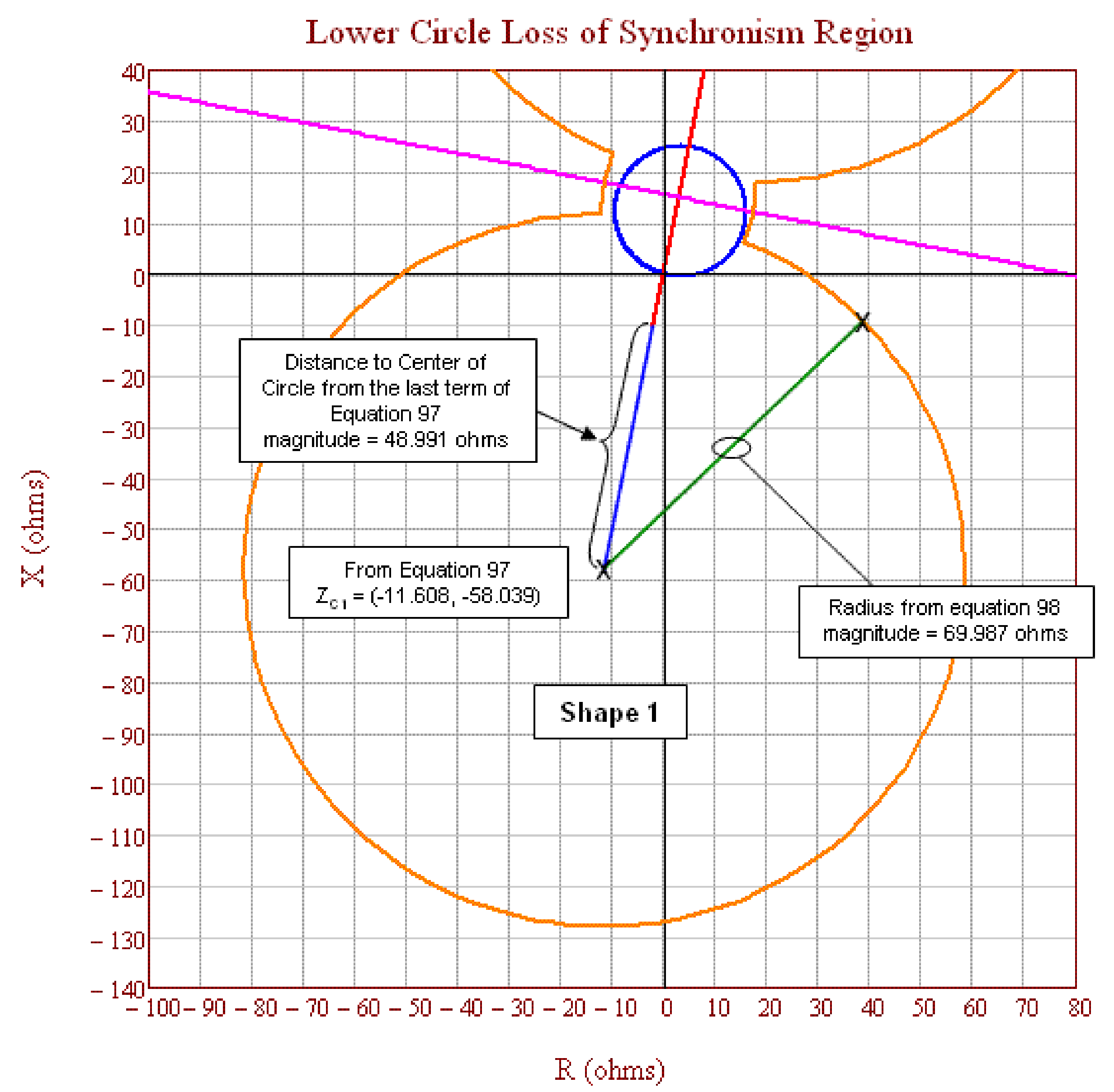


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

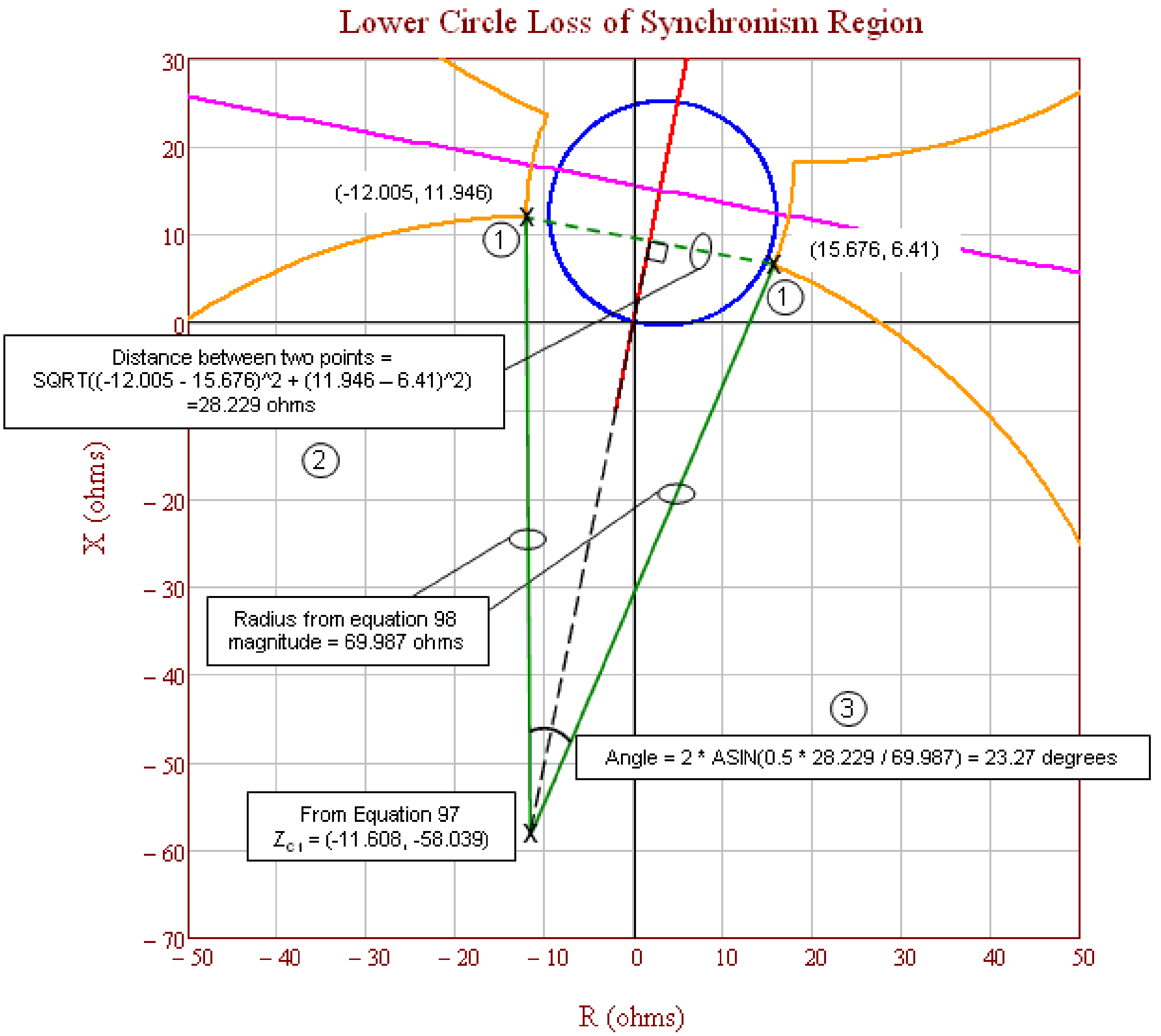


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

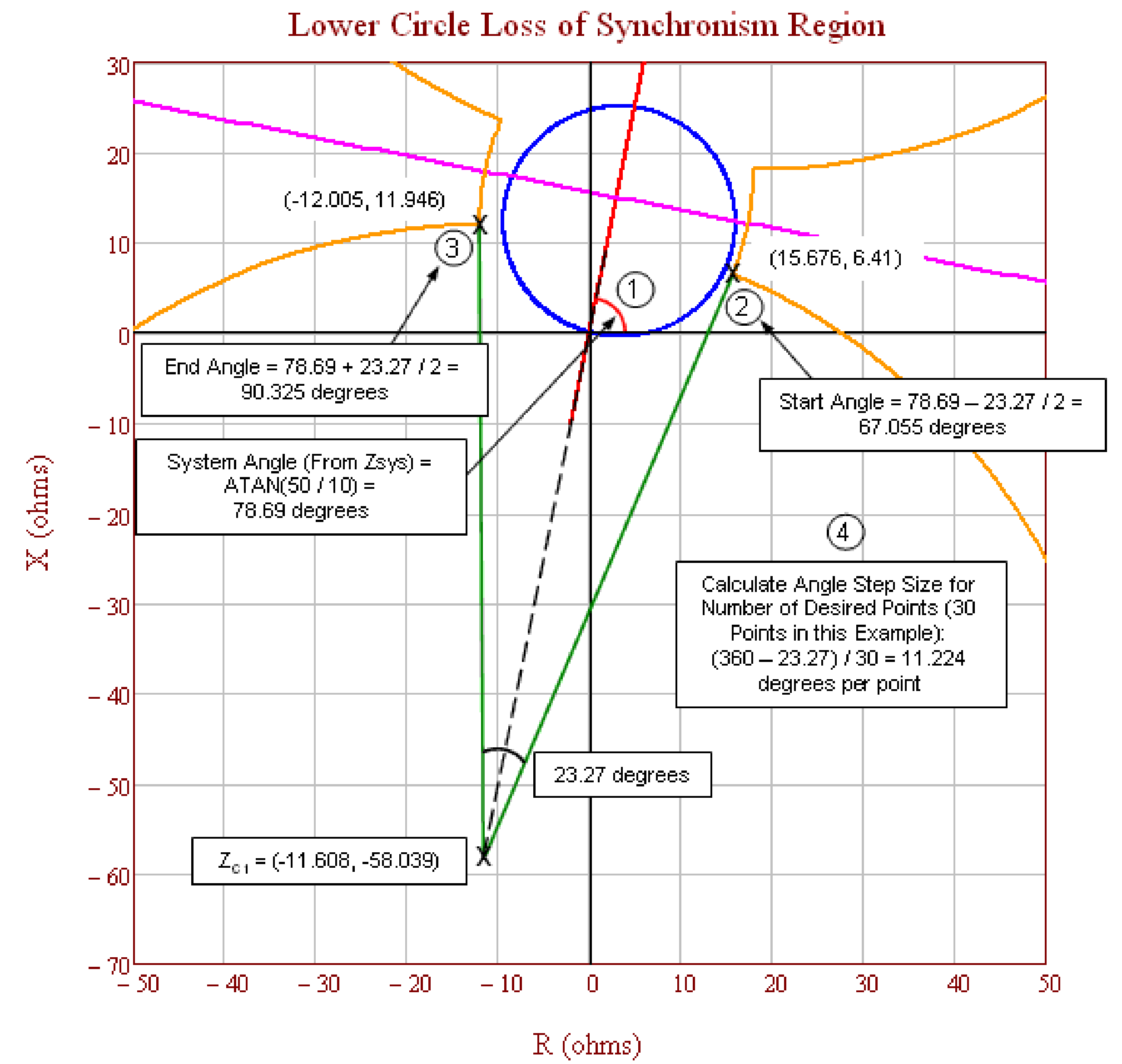


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

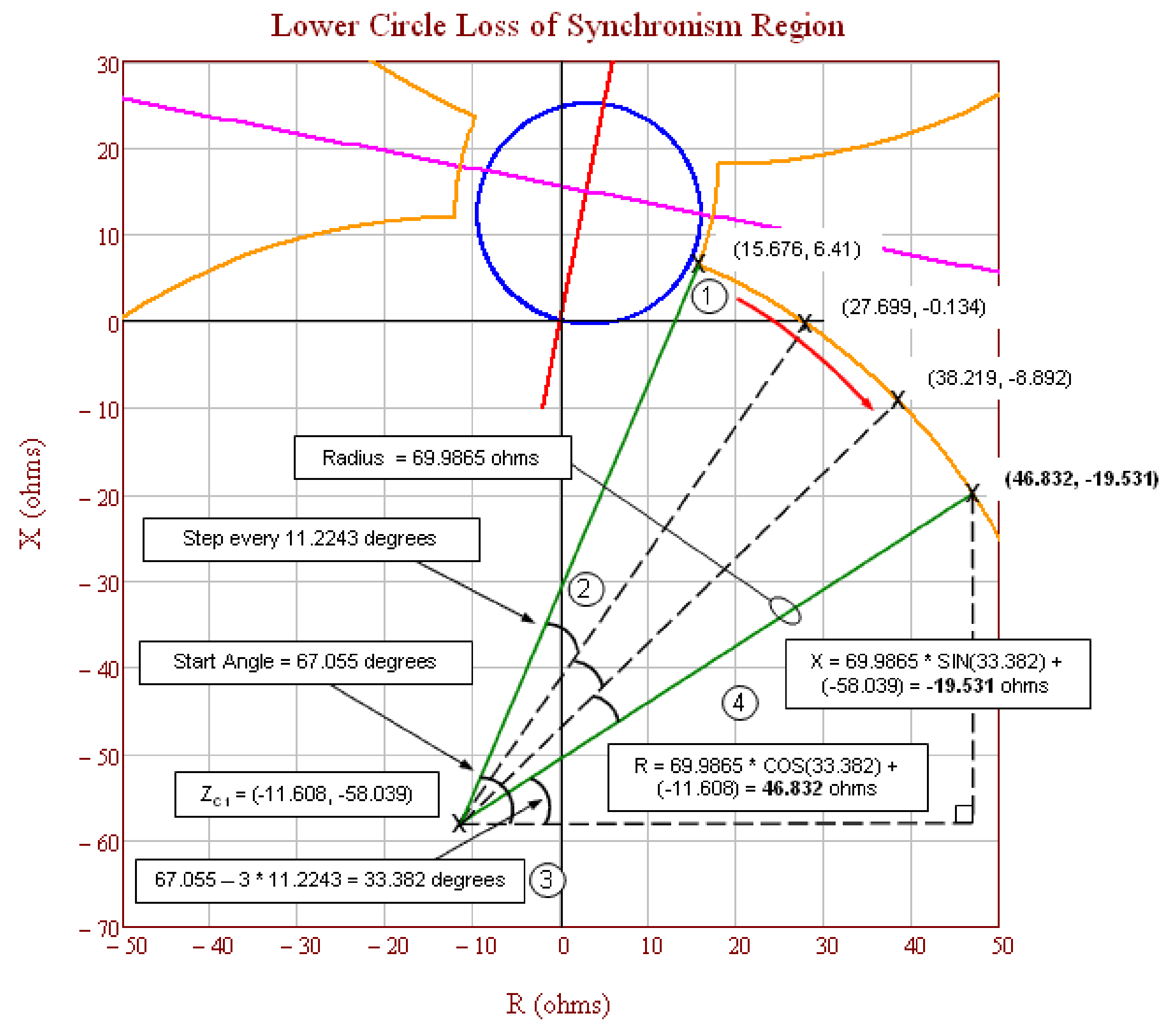


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

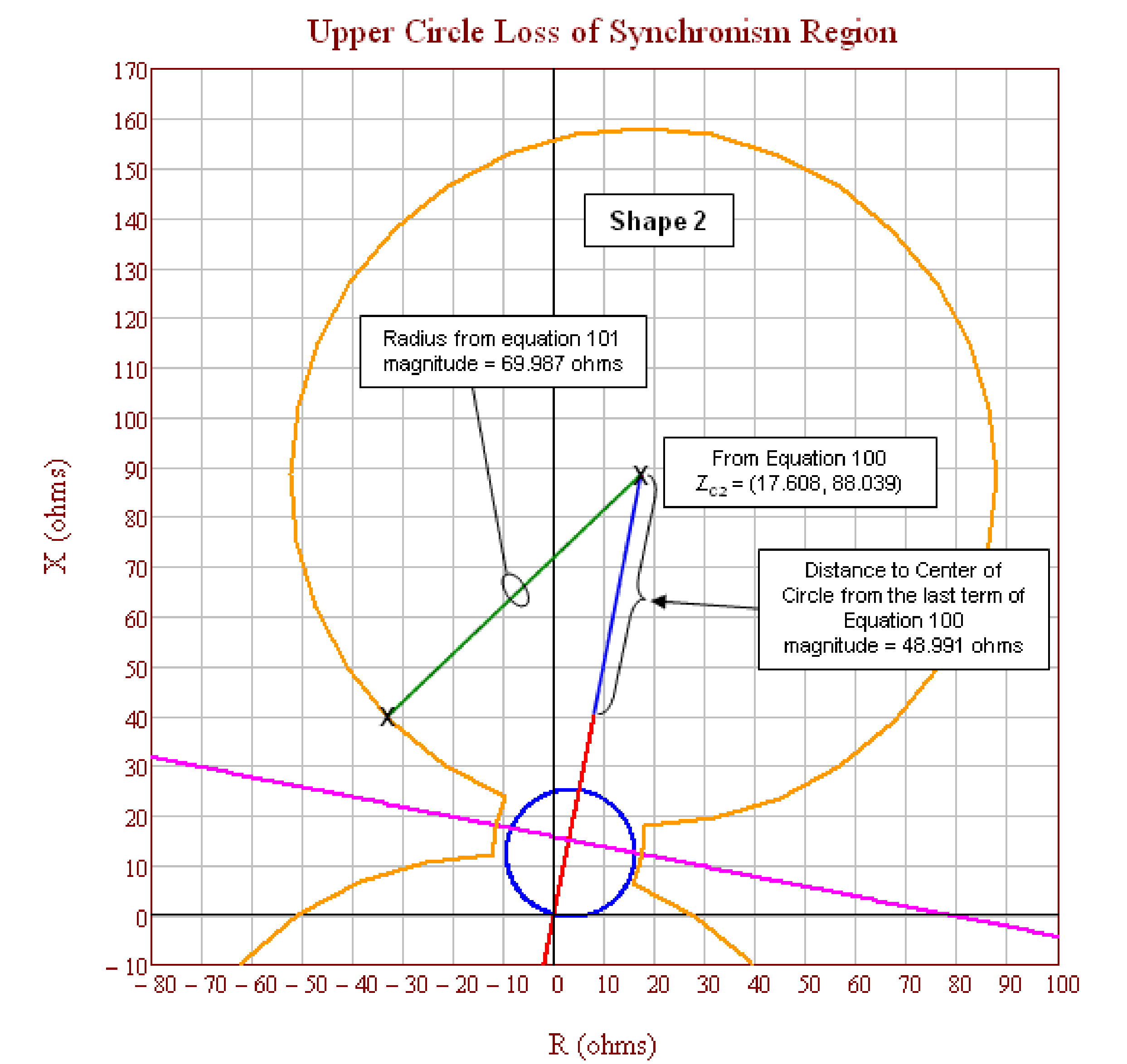


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

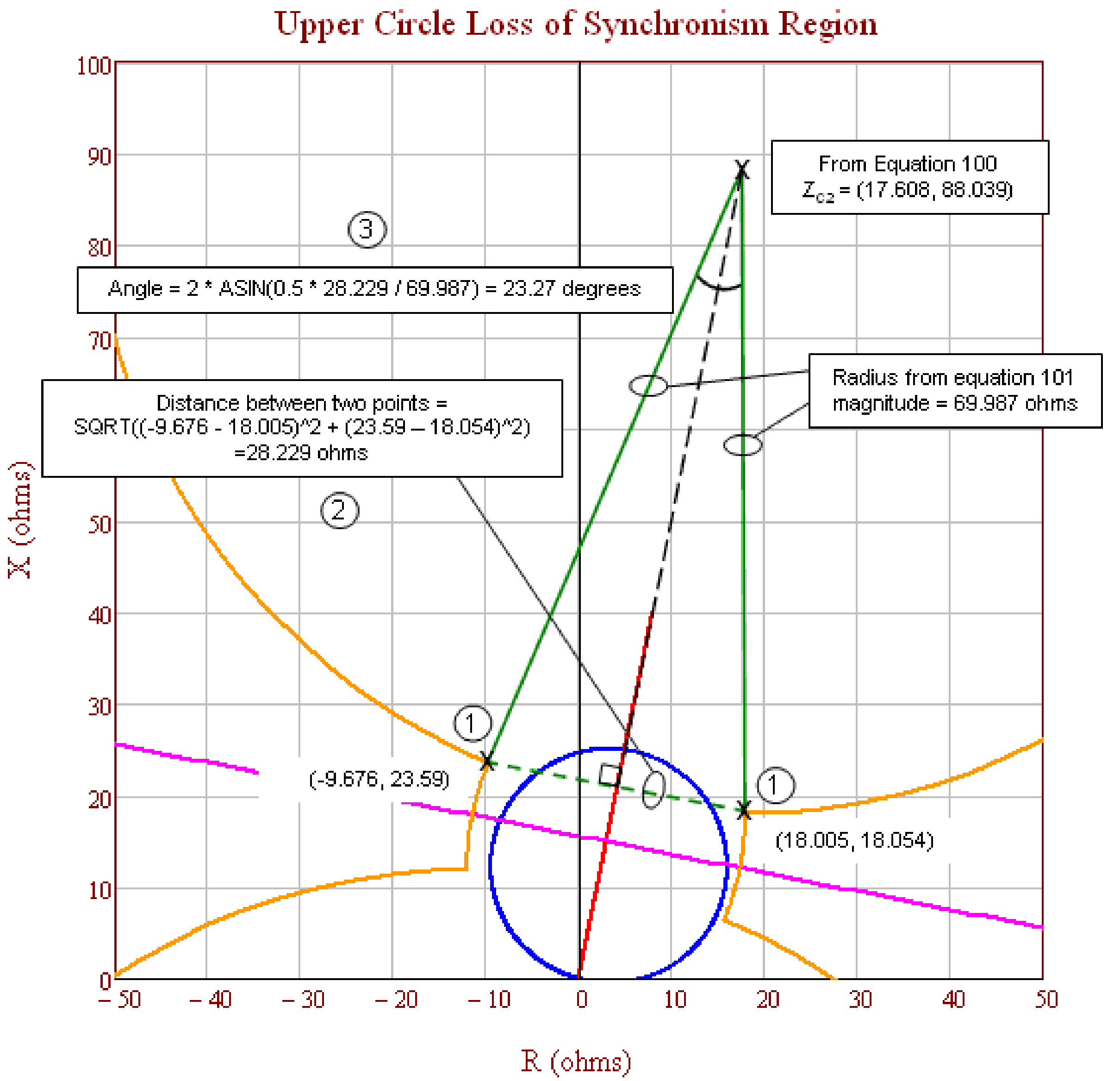


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

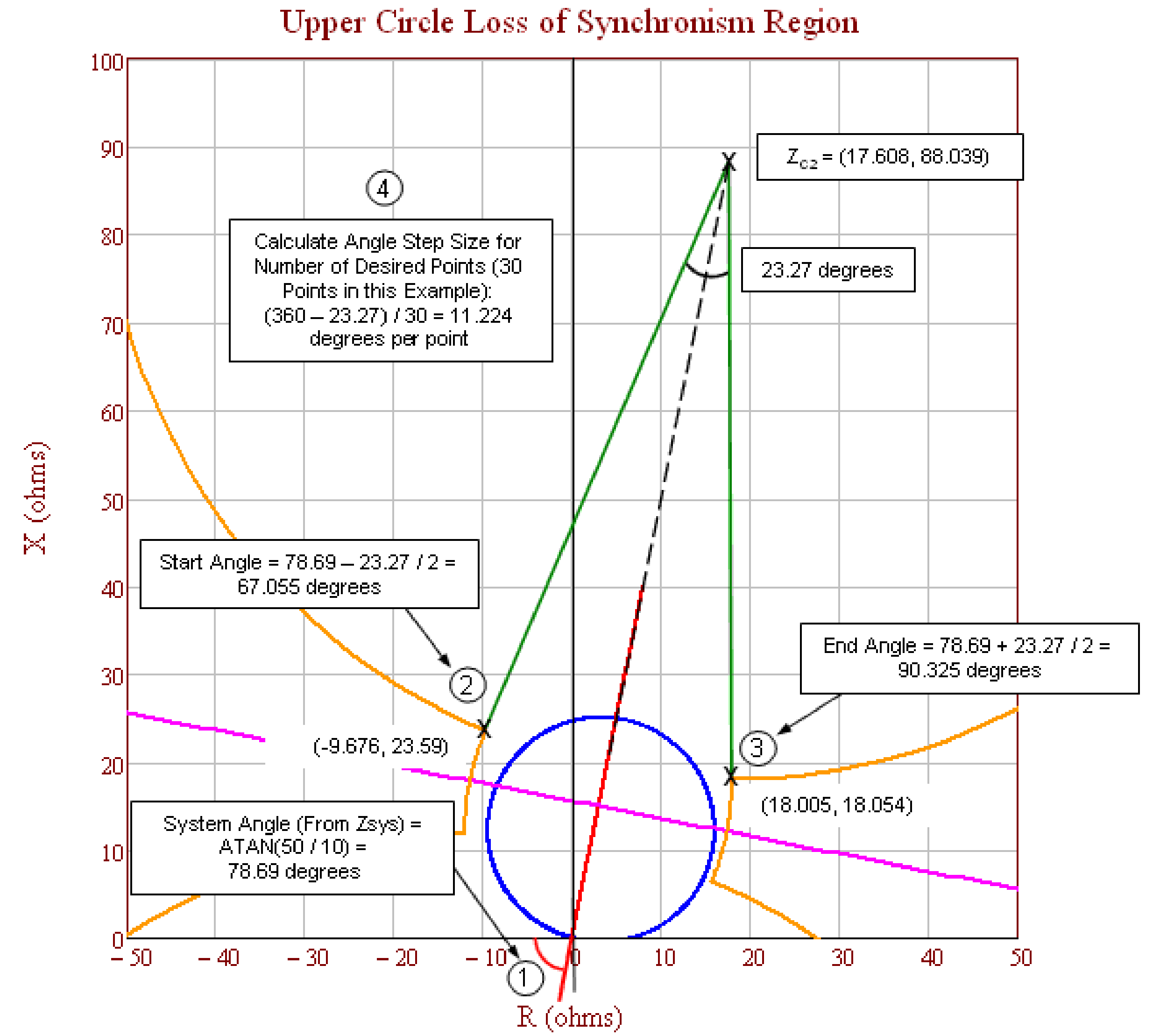


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

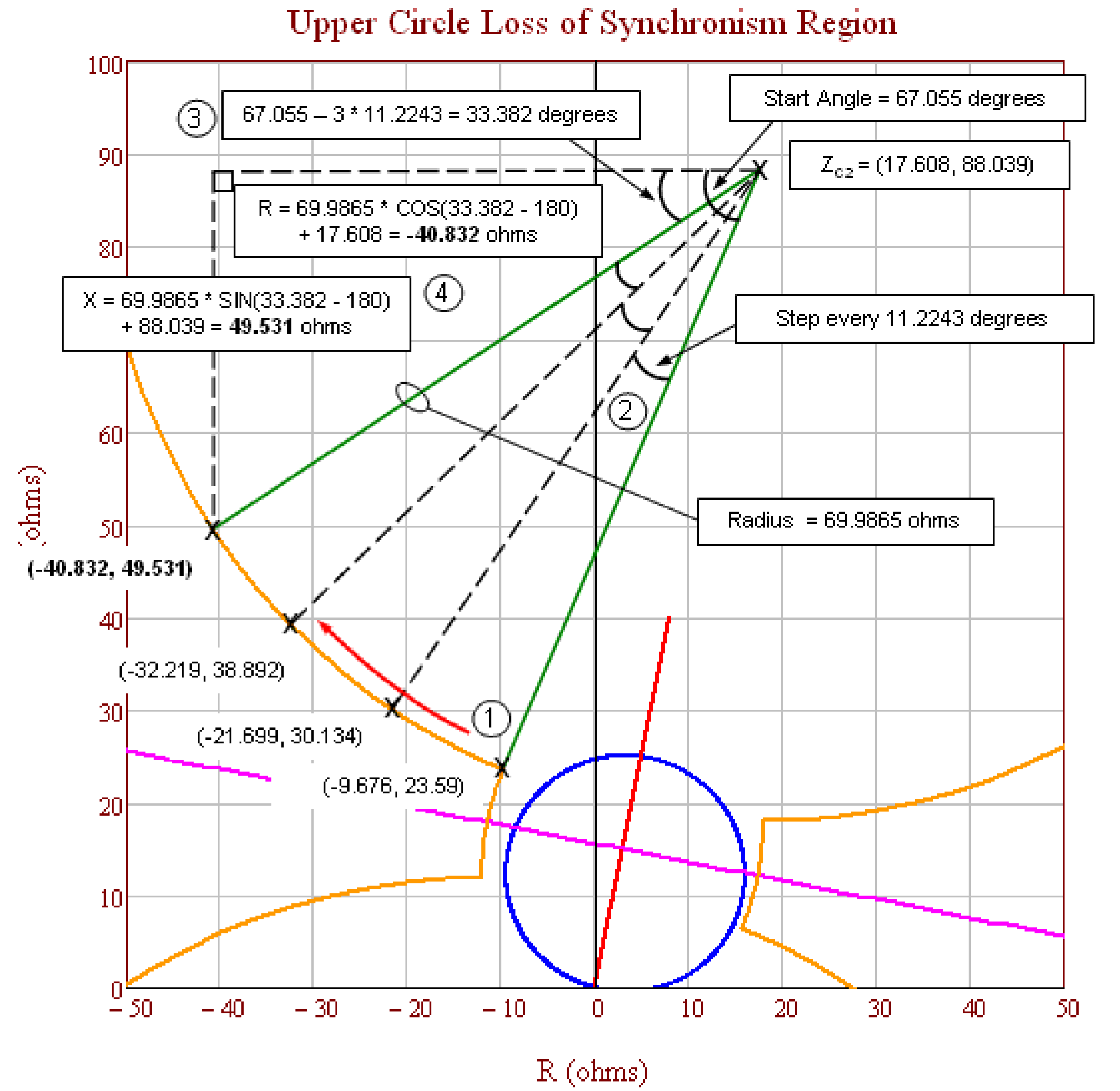


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-2 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

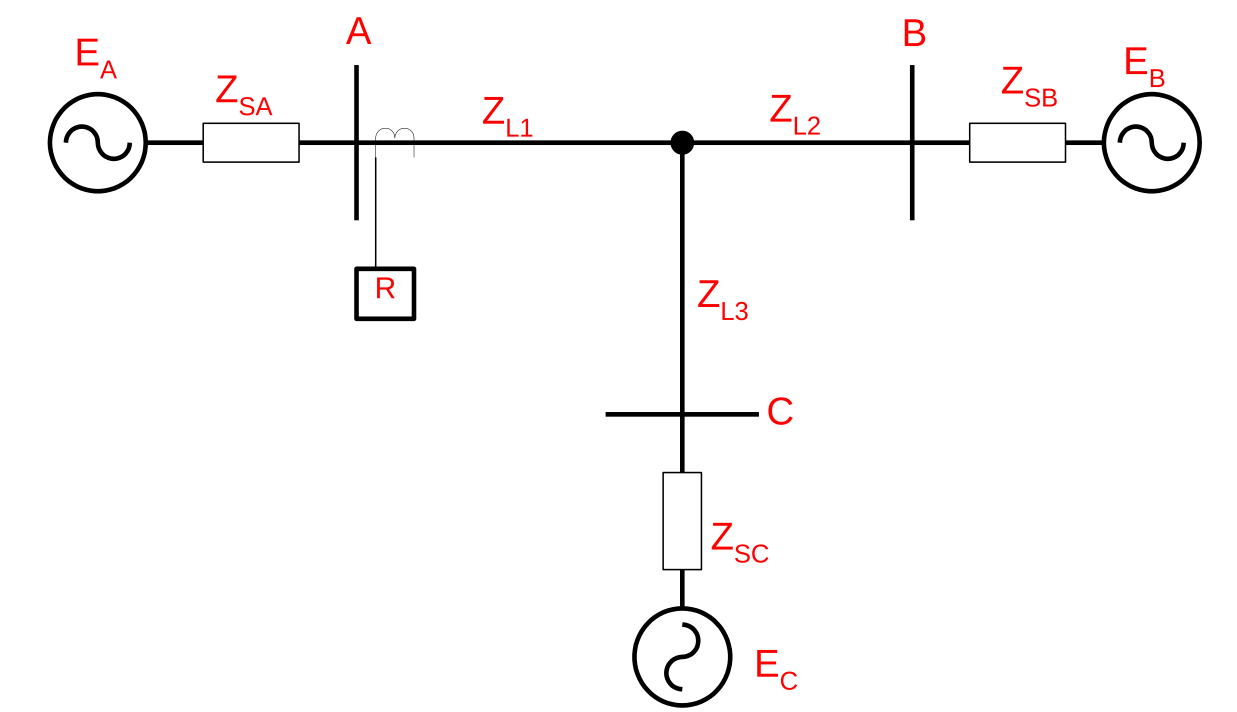


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

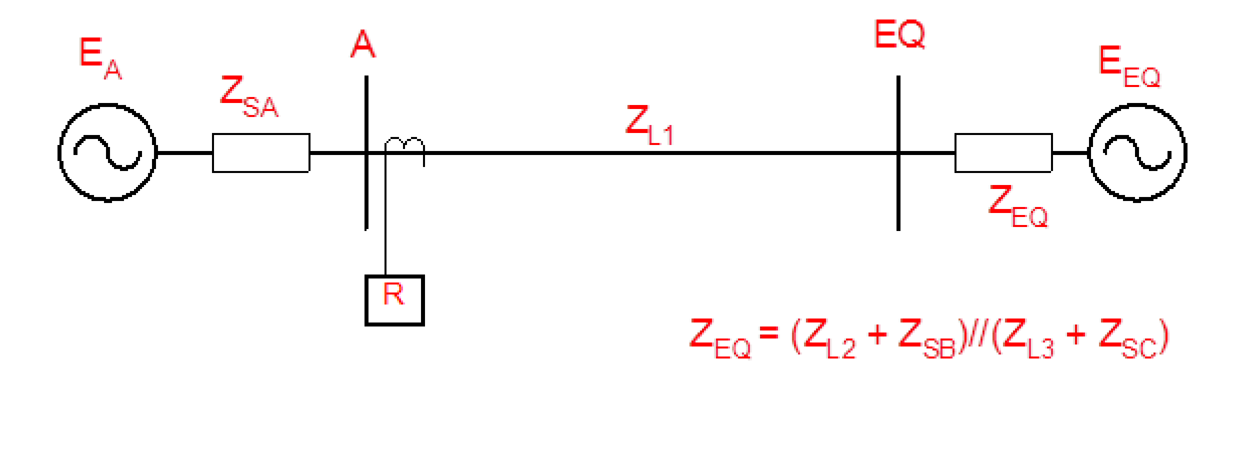


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

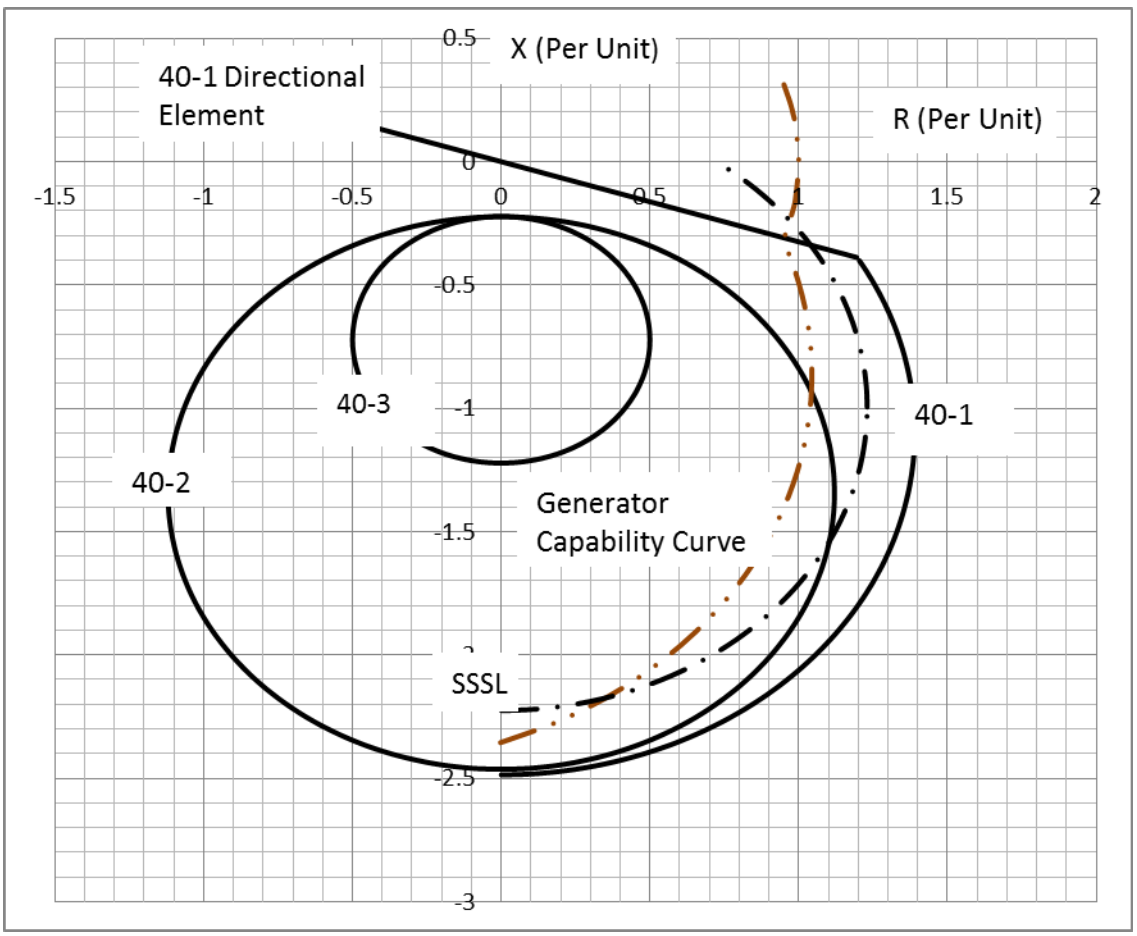


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

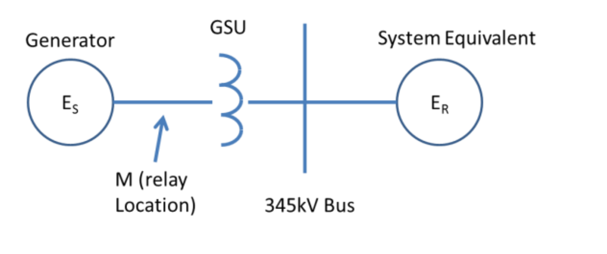

Figure 17: Simple one-line diagram of the system to be evaluated.

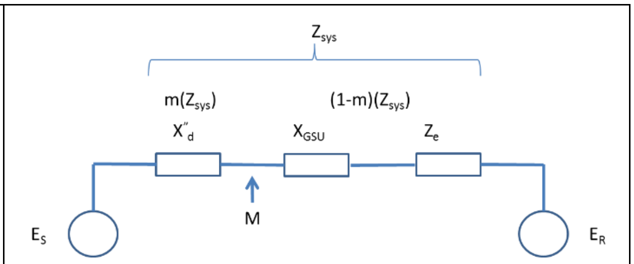

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

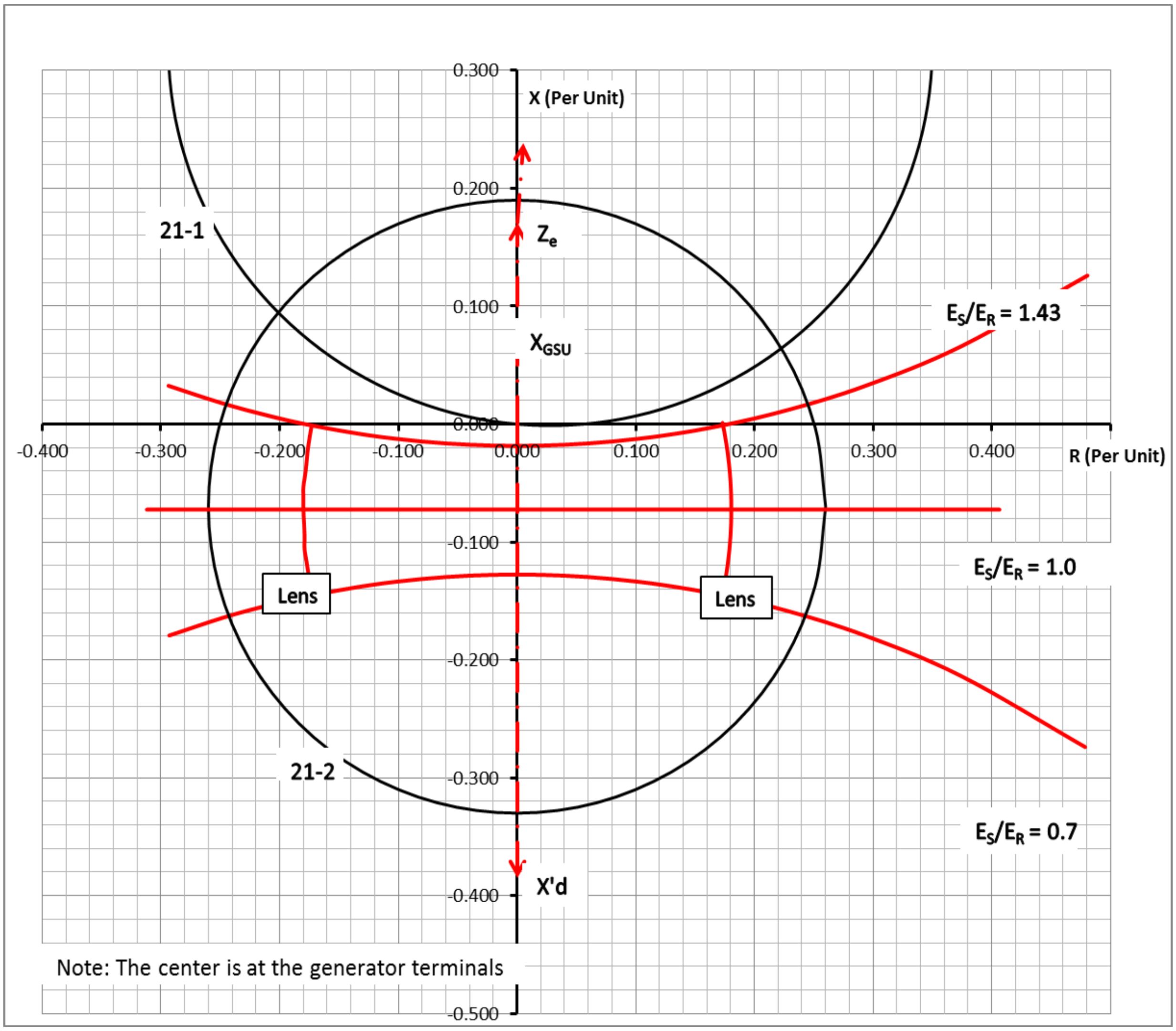

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

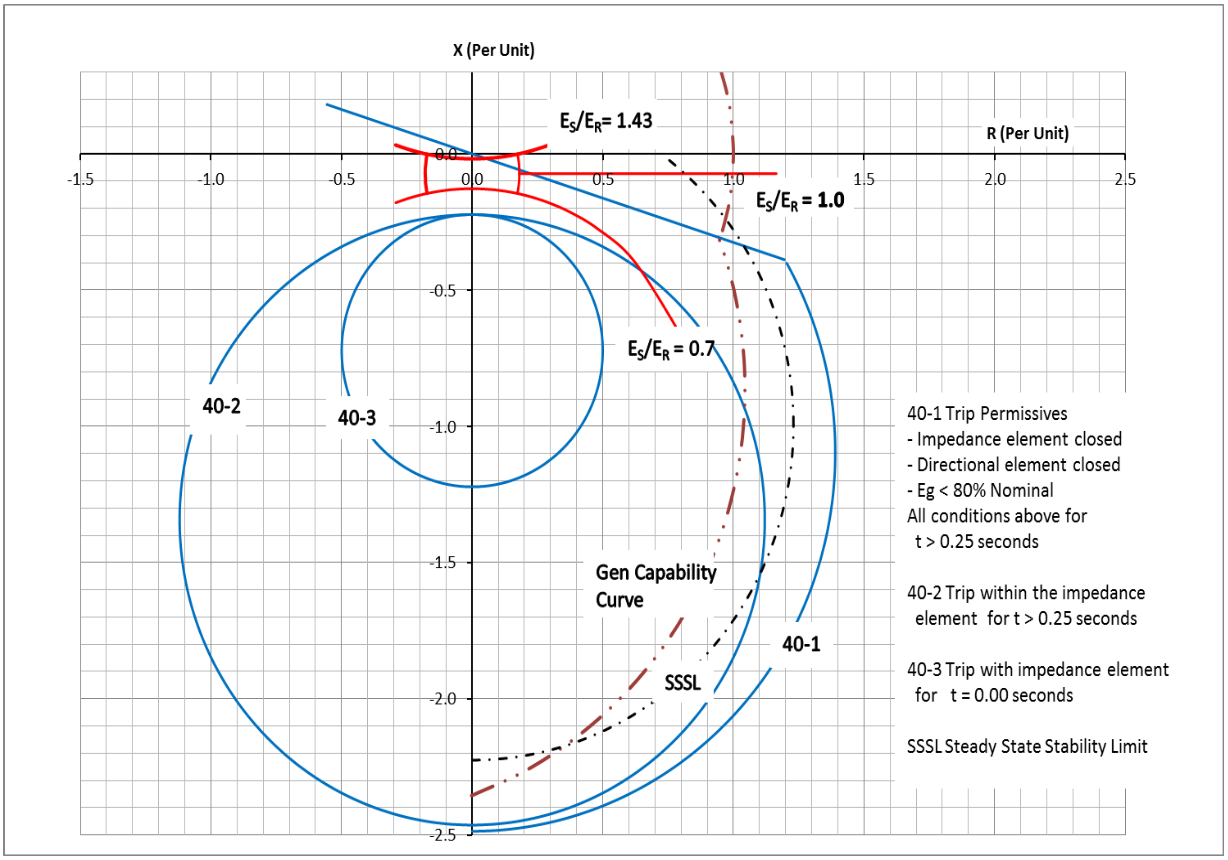

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer ($X_{T)}$, and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

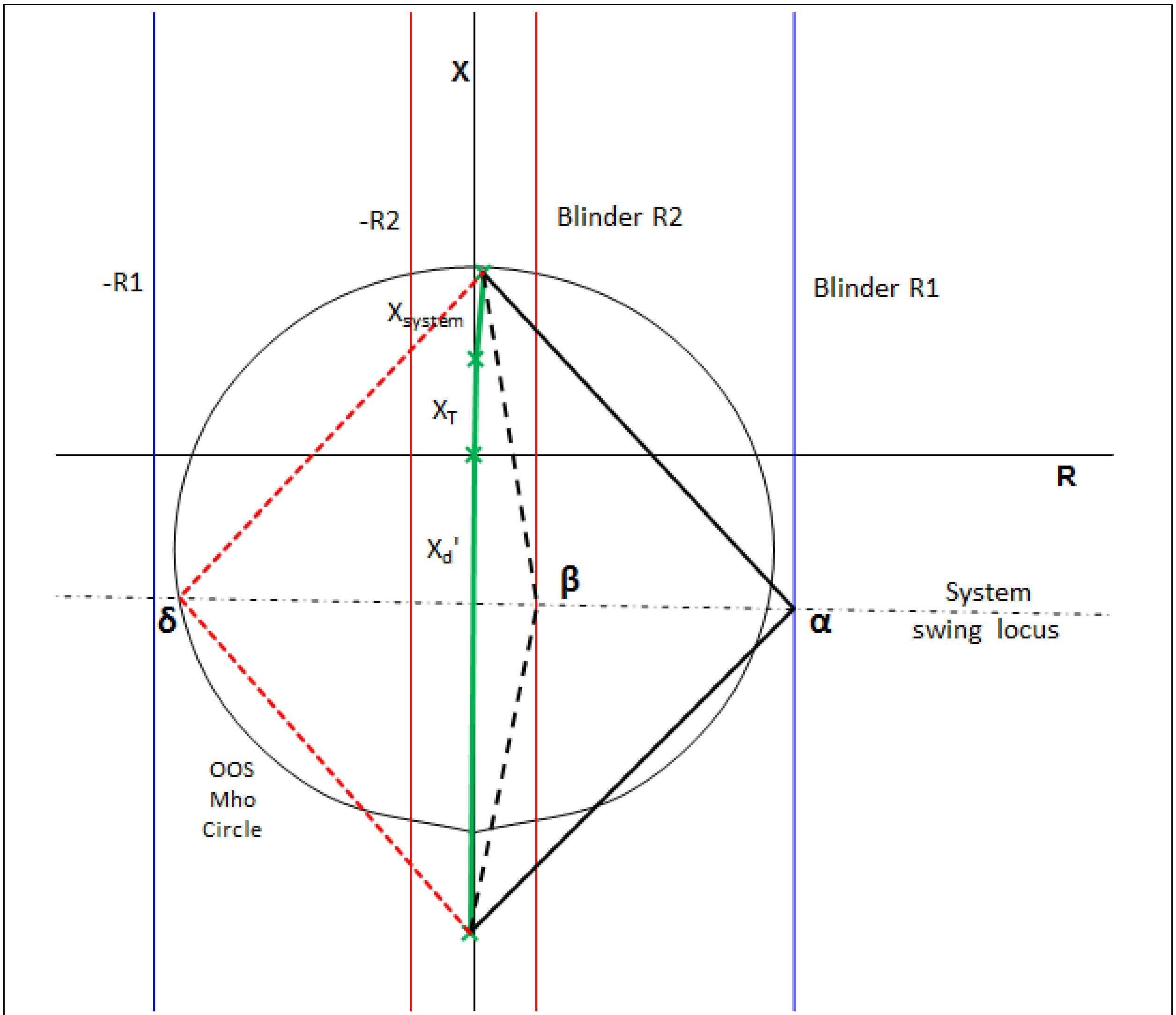

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

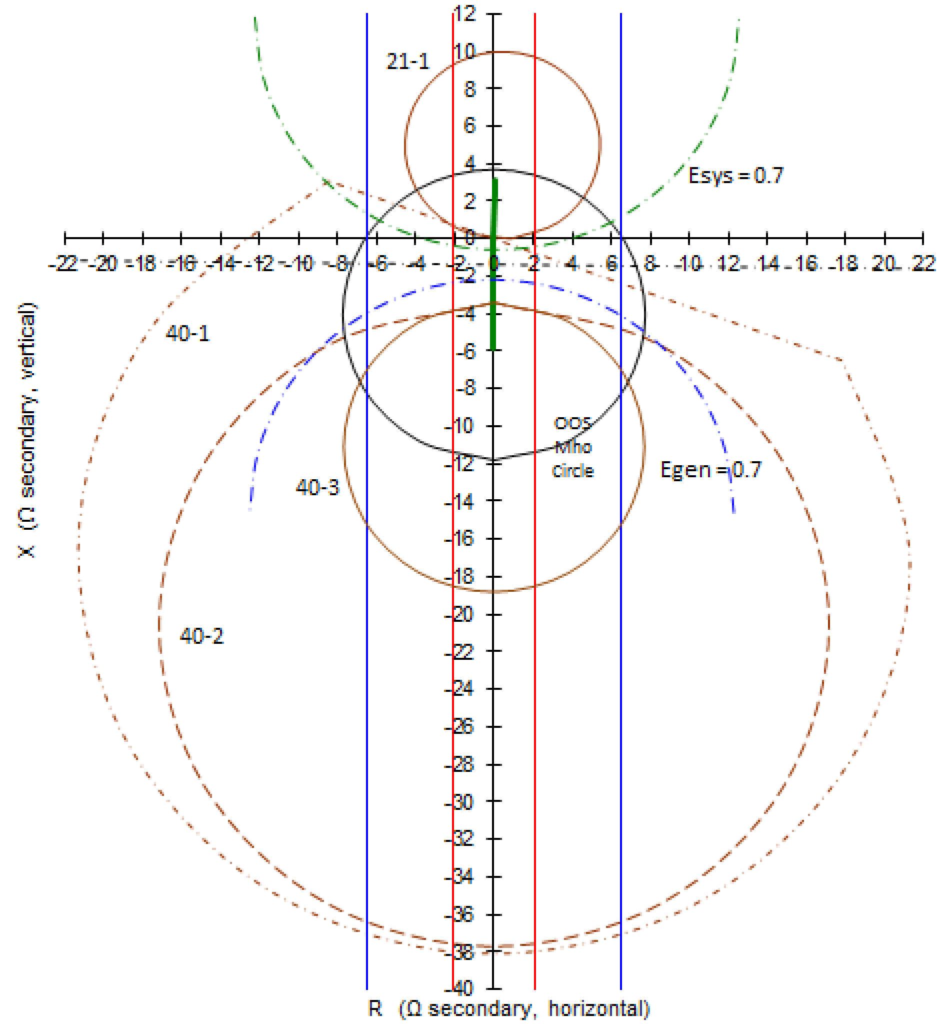

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-2 – Attachment B criteria or can be excluded under the PRC-026-2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-2 – Attachment B criteria.

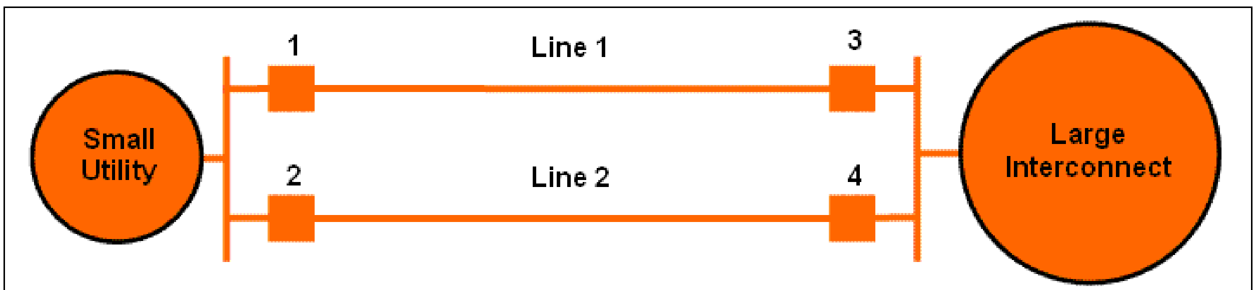

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

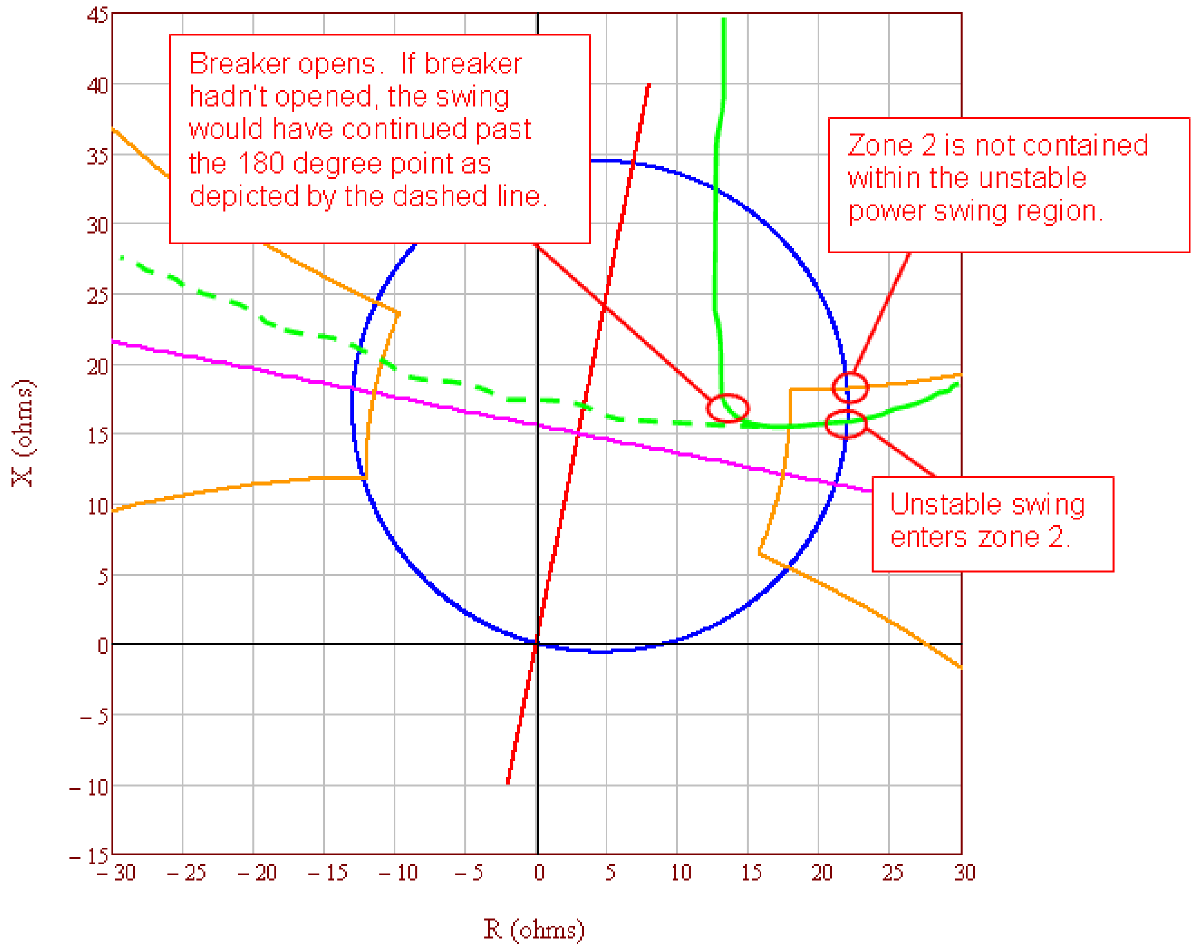

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

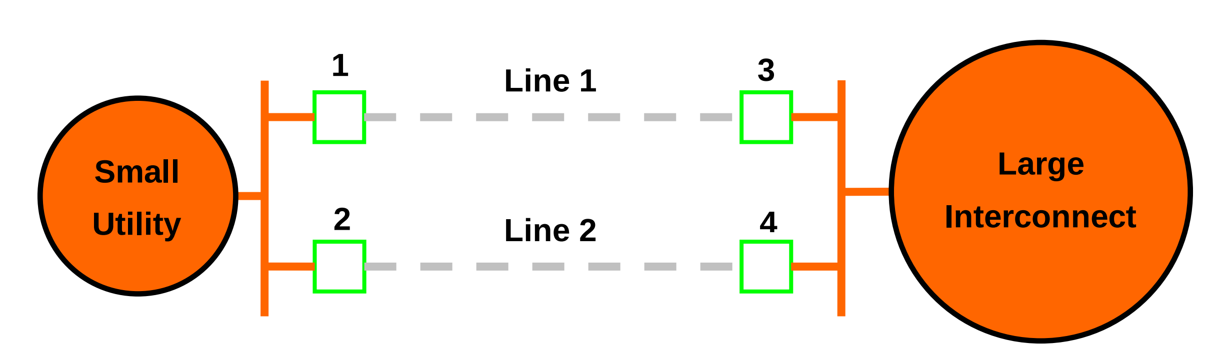

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

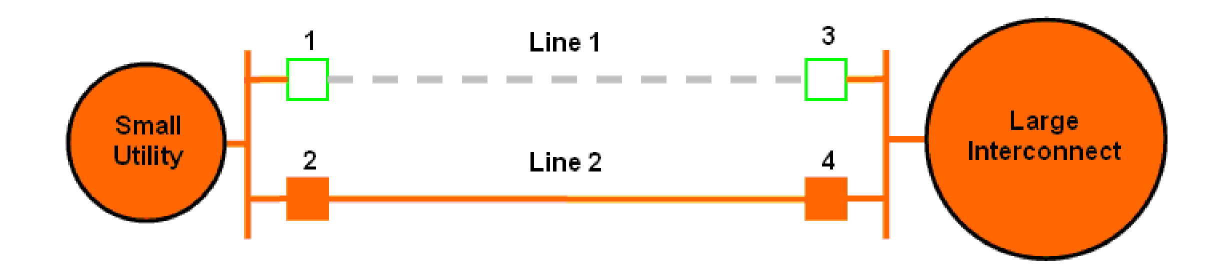

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

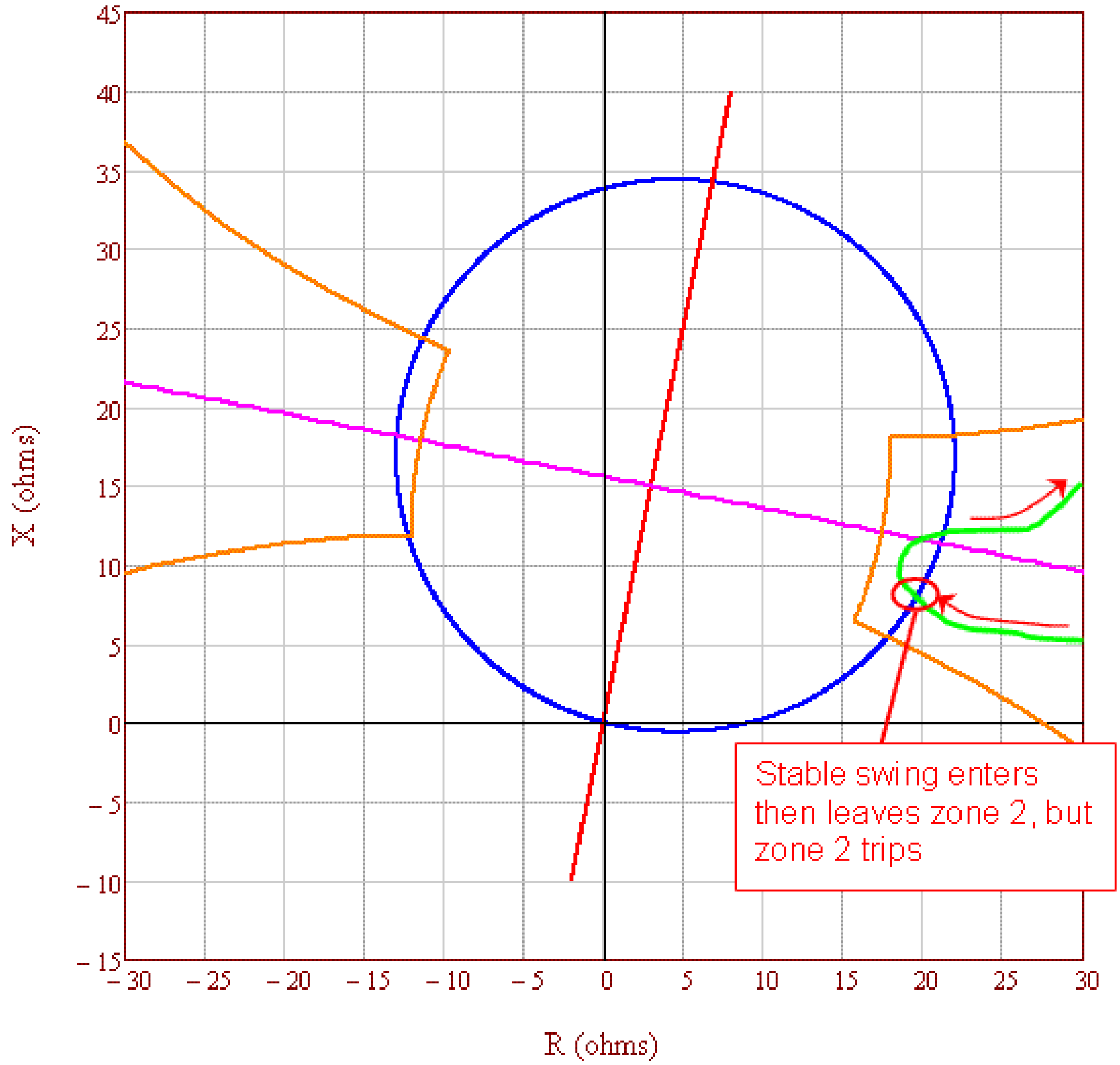

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

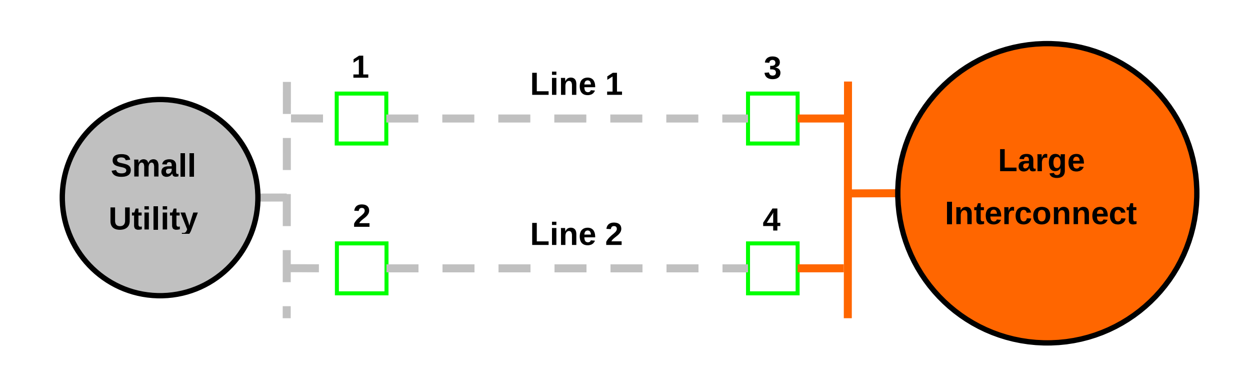

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18-10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-2**

3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. **Effective Dates:** **See Implementation Plan**

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event~~, ~~, ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event~~.~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~ 2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-~~1~~ 2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~ 2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-~~1~~ 2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-~~1~~ 2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-~~1~~ 2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	TBD	Adopted by NERC Board of Trustees	Revised

PRC-026-~~1~~2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., “load-responsive”) including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-~~1~~2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-~~1~~ 2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-~~1~~2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-2~~1~~ Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-~~1~~2 – Attachment B.

[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., “TPL”) and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the~~ any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission ~~lines to~~lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-~~1~~ 2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-~~1~~ 2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-~~1~~ 2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-~~1~~ 2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-~~1~~ 2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-~~1~~2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-~~1~~2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-~~1~~ 2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-~~1~~2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-~~1~~2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-~~1~~2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-~~1~~2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

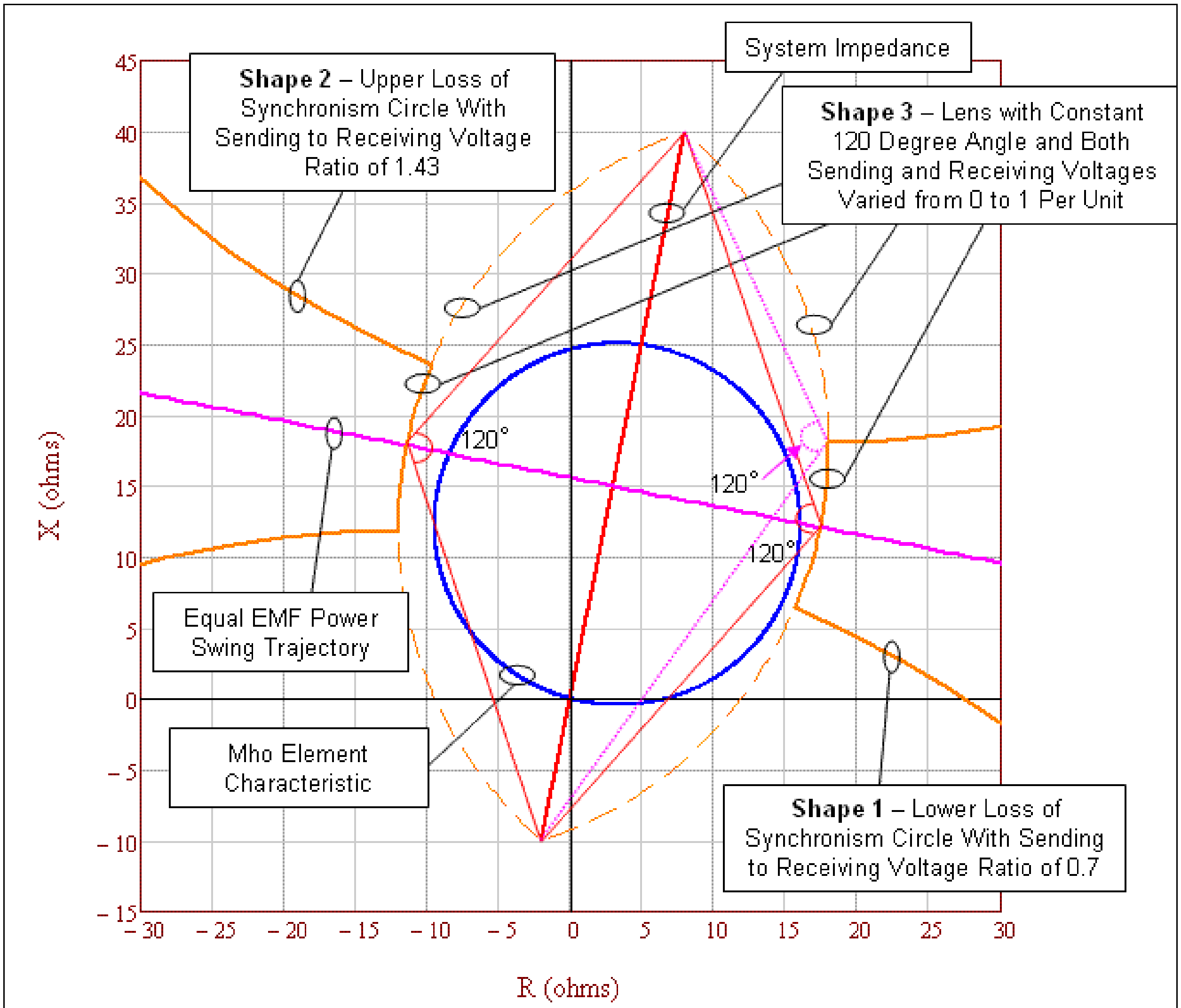


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1.

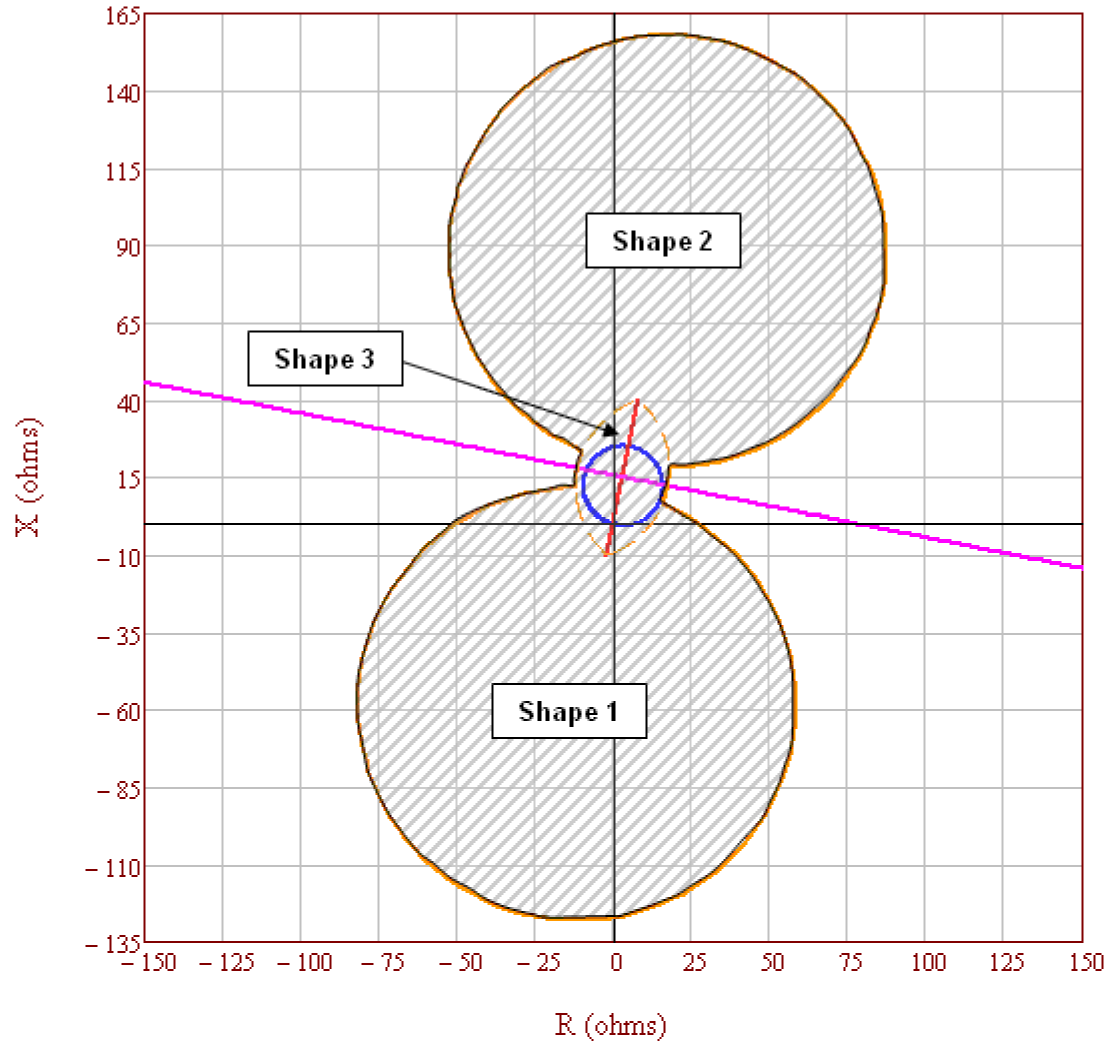


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No.1.

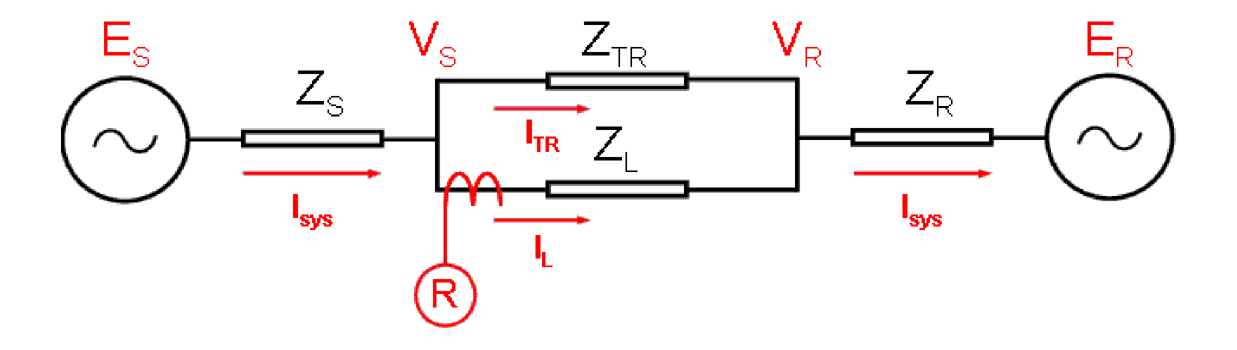


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

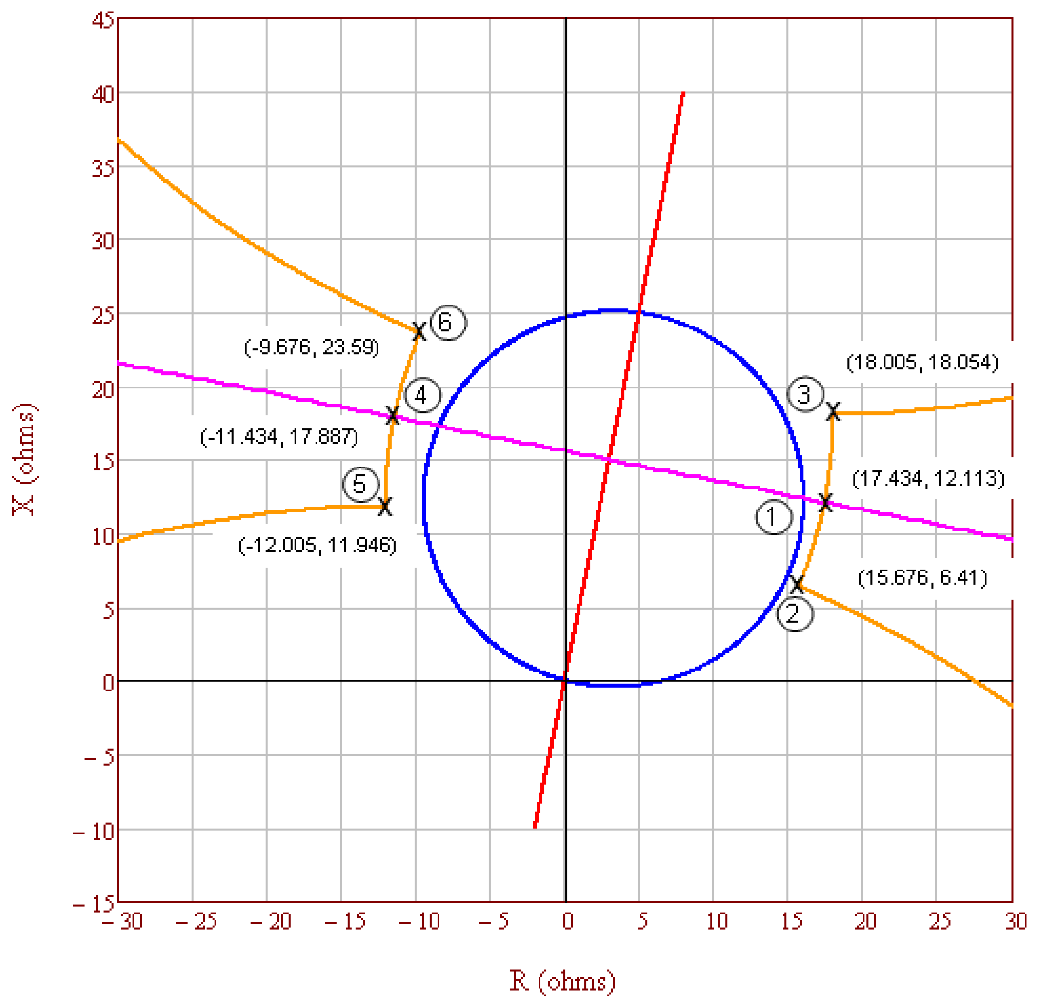


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

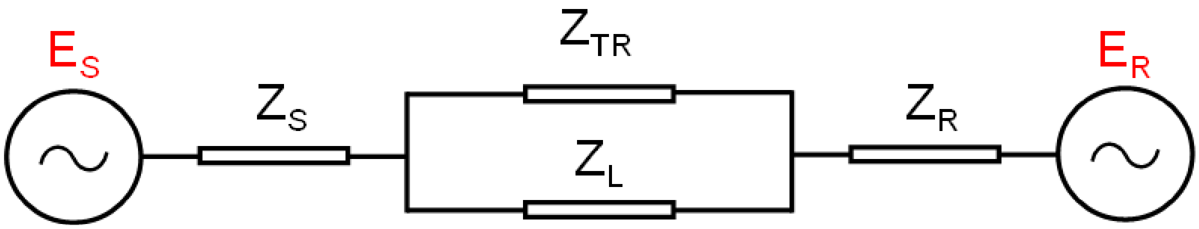
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1°\, A]$
	$V_S = 95{,}756\angle - 106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle - 106.1°\, V}{4{,}511\angle 131.1°\, A}$
	$Z_{L-Relay} = -11.434 + j17.887\,\Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 240°\, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\, V$		
Eq. (39)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\,\Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega)}{((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

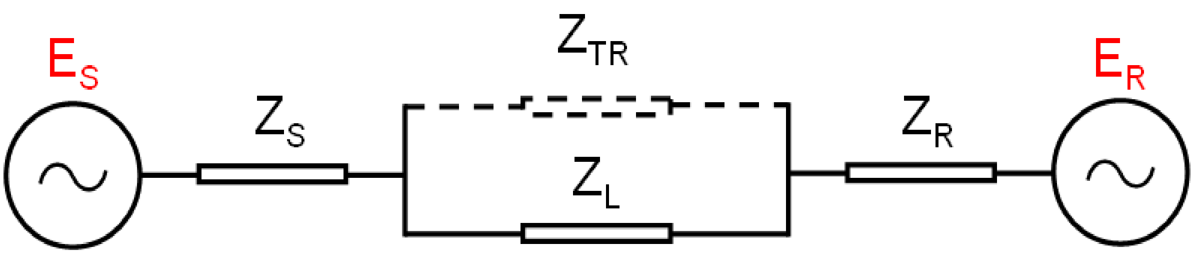
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle -110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

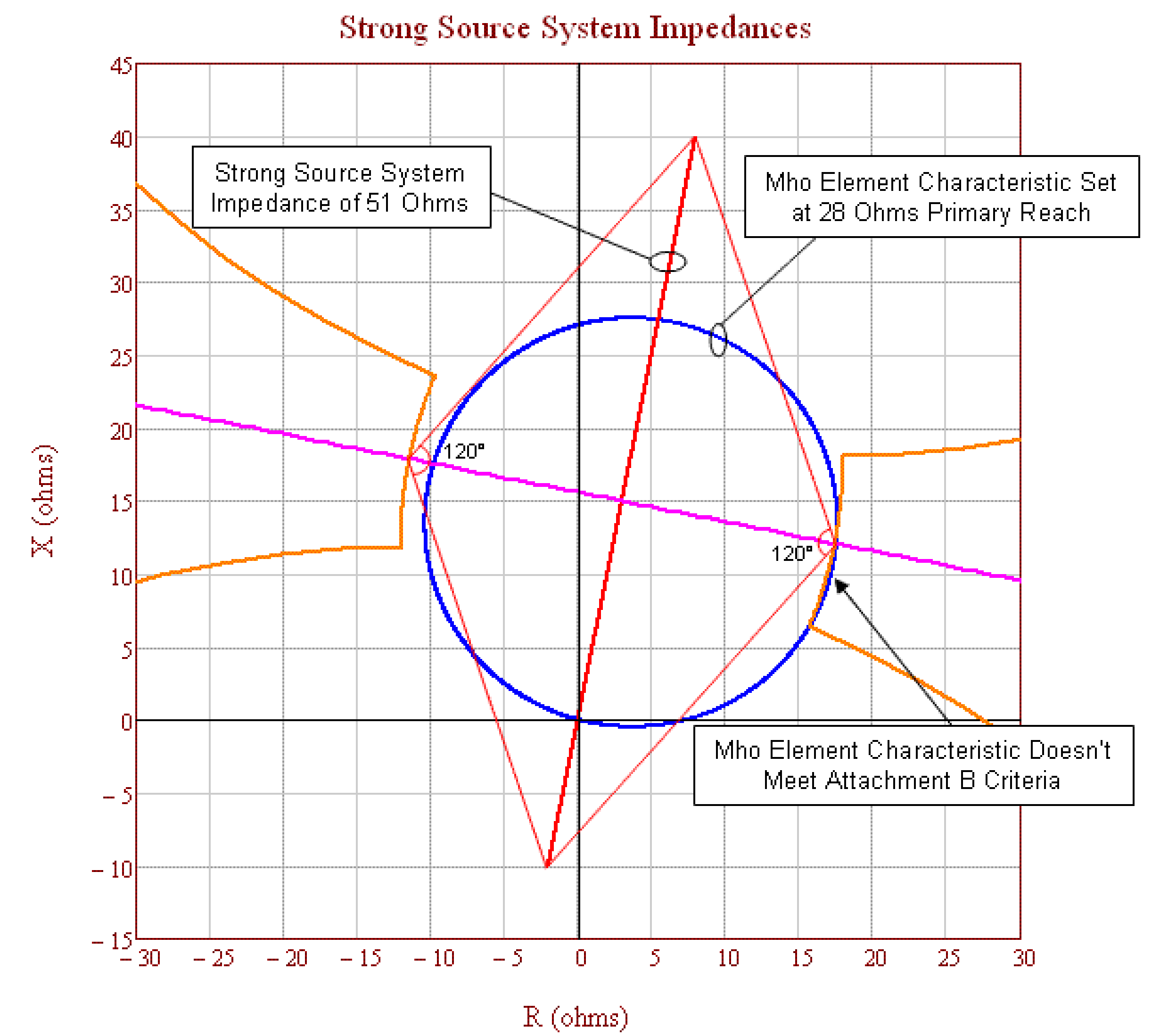


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-~~1~~2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

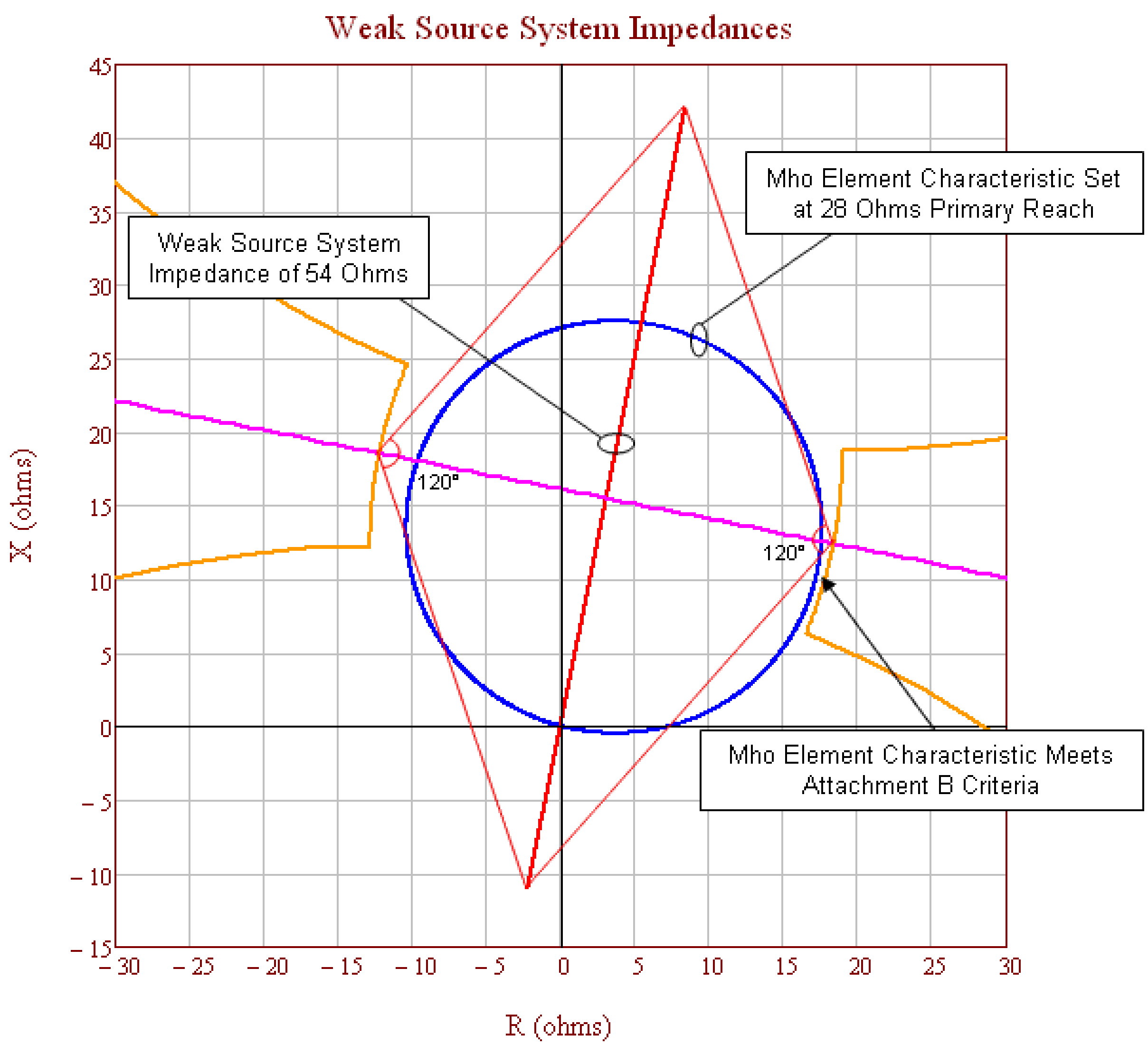


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

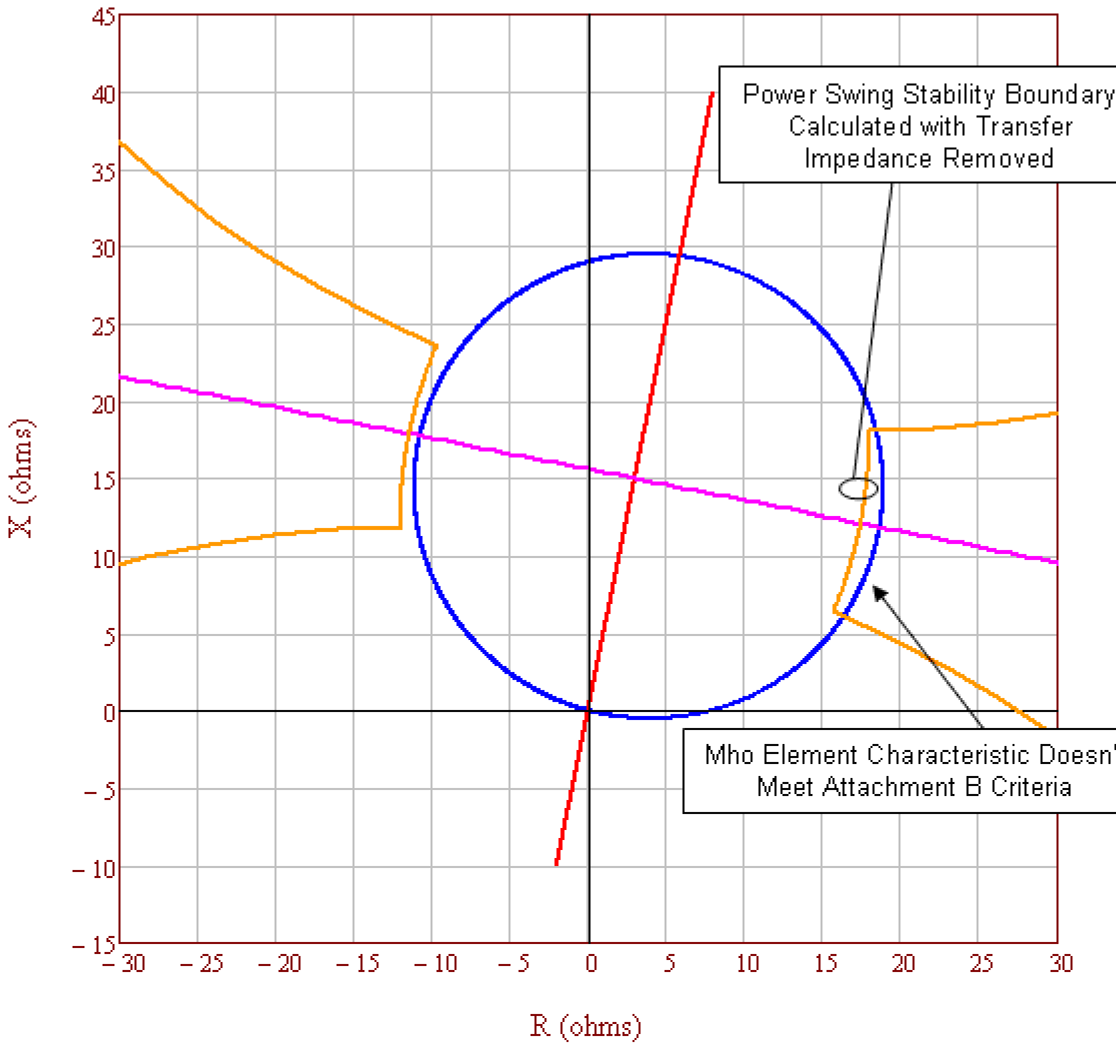


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

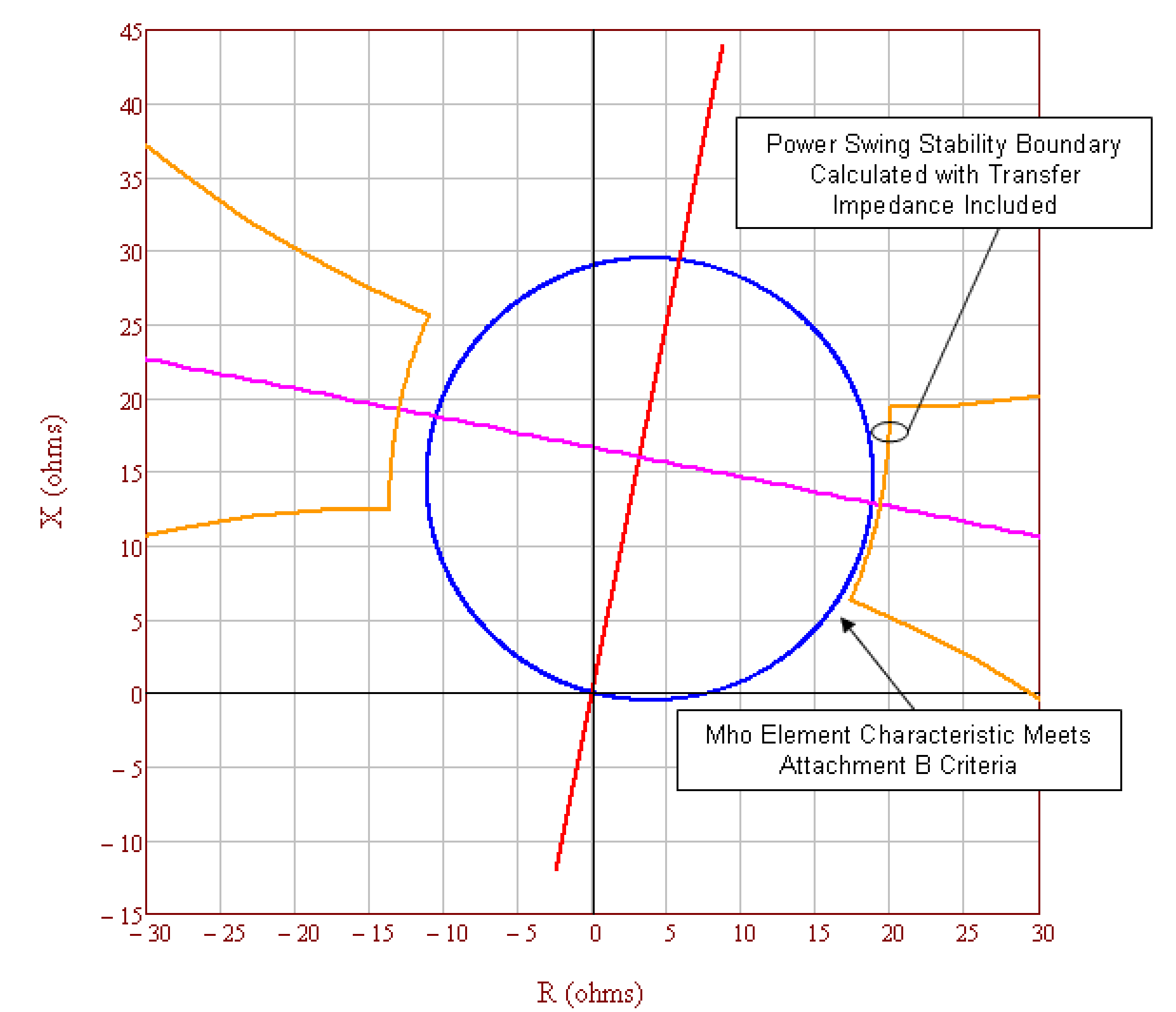


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-~~1~~ 2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~ 2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-~~1~~ 2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~ 2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

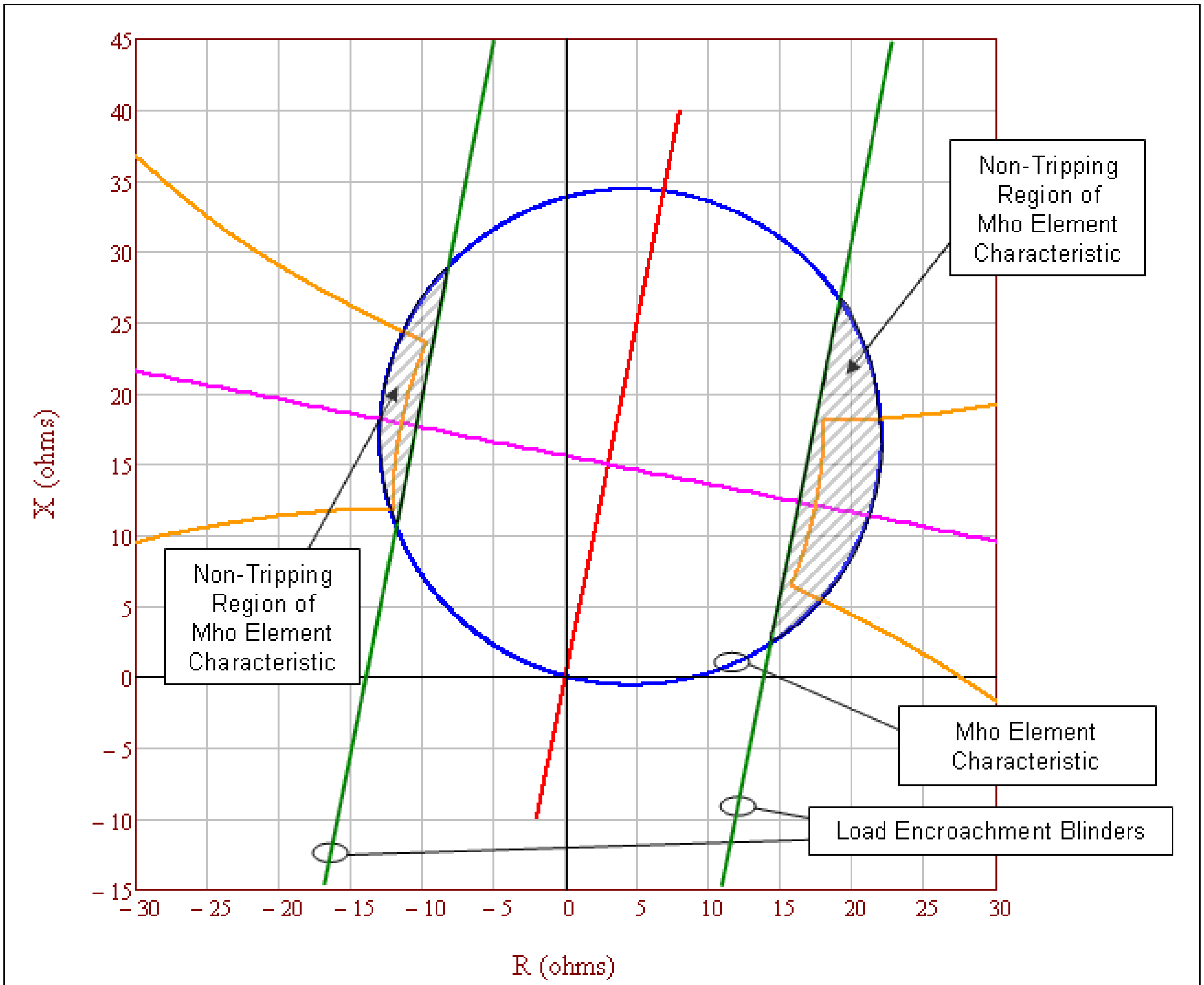


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-~~1~~ 2– Attachment B, Criterion A.

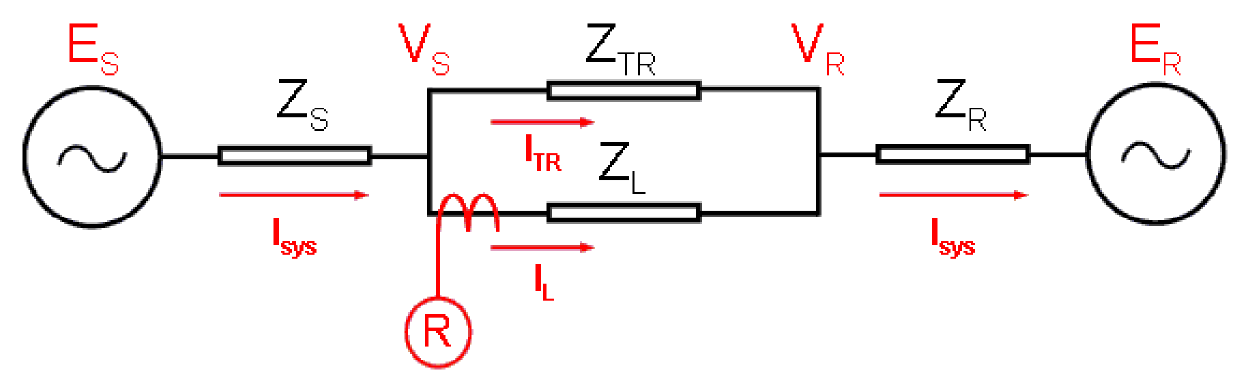


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

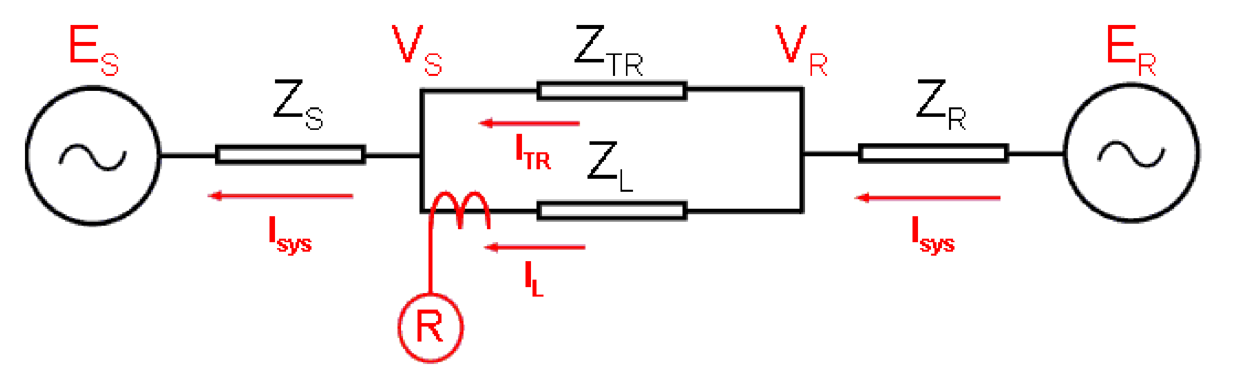


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \dfrac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \dfrac{V_R}{I_L} = Z_L + Z_S + \dfrac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\dfrac{I_{TR}}{I_L} = \dfrac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

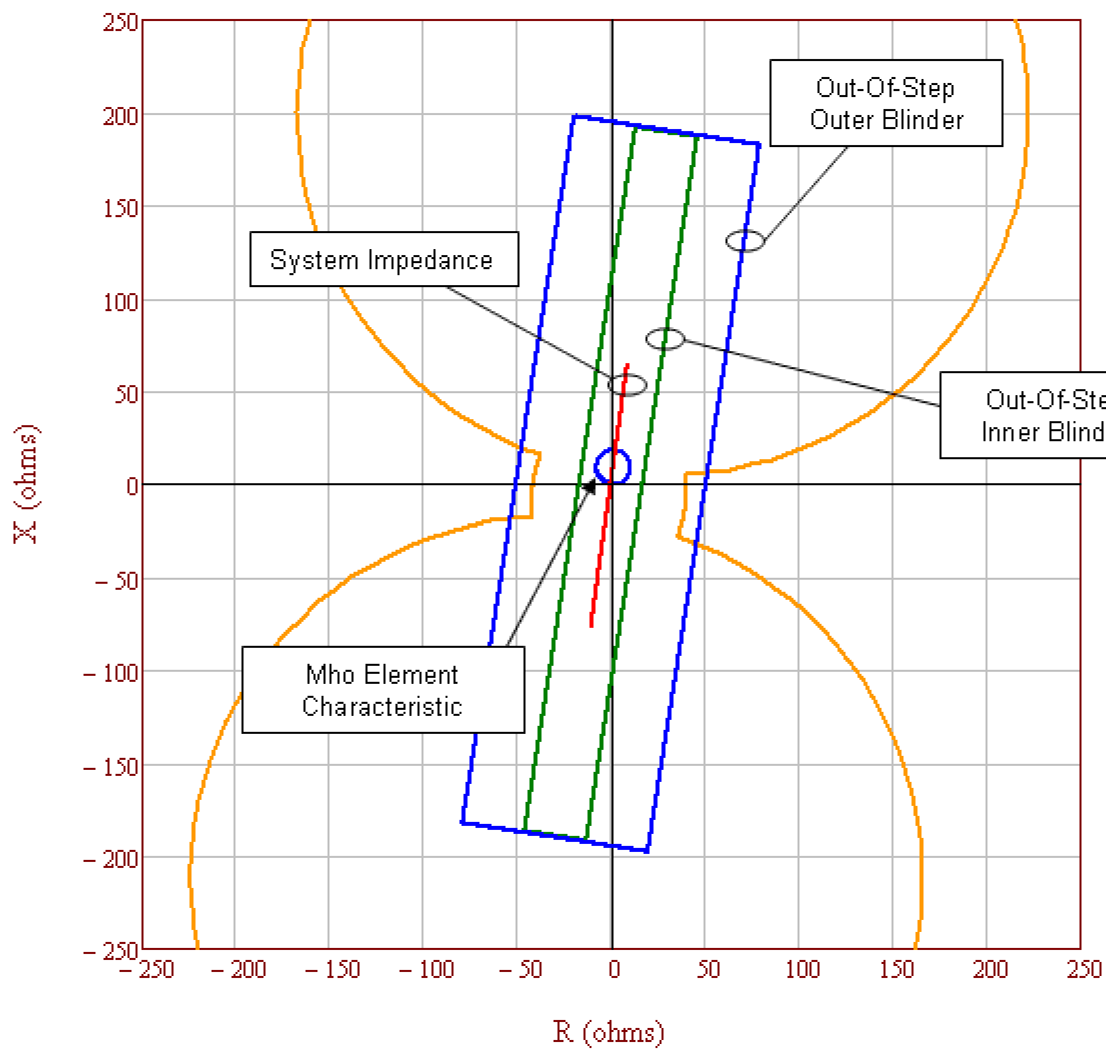


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)		
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.		
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.		
Given:	$E_S = 0.7$	$E_R = 1.0$
Eq. (95)	$N = \frac{\|E_S\|}{\|E_R\|} = \frac{0.7}{1.0} = 0.7$	
The total system impedance as seen by the relay with infeed formulae applied.		
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$; $Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$	
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$	
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$	
	$Z_{sys} = 10 + j50\ \Omega$	
The calculated coordinates of the lower loss-of-synchronism circle center.		
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$	
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$	
	$Z_{C1} = -11.608 - j58.039\ \Omega$	
The calculated radius of the lower loss-of-synchronism circle.		
Eq. (98)	$r_a = \left\|\frac{N \times Z_{sys}}{1 - N^2}\right\|$	
	$r_a = \left\|\frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right\|$	
	$r_a = 69.987\ \Omega$	
The calculated coordinates of the upper loss-of-synchronism circle center.		
Given:	$E_S = 1.0$	$E_R = 0.7$

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

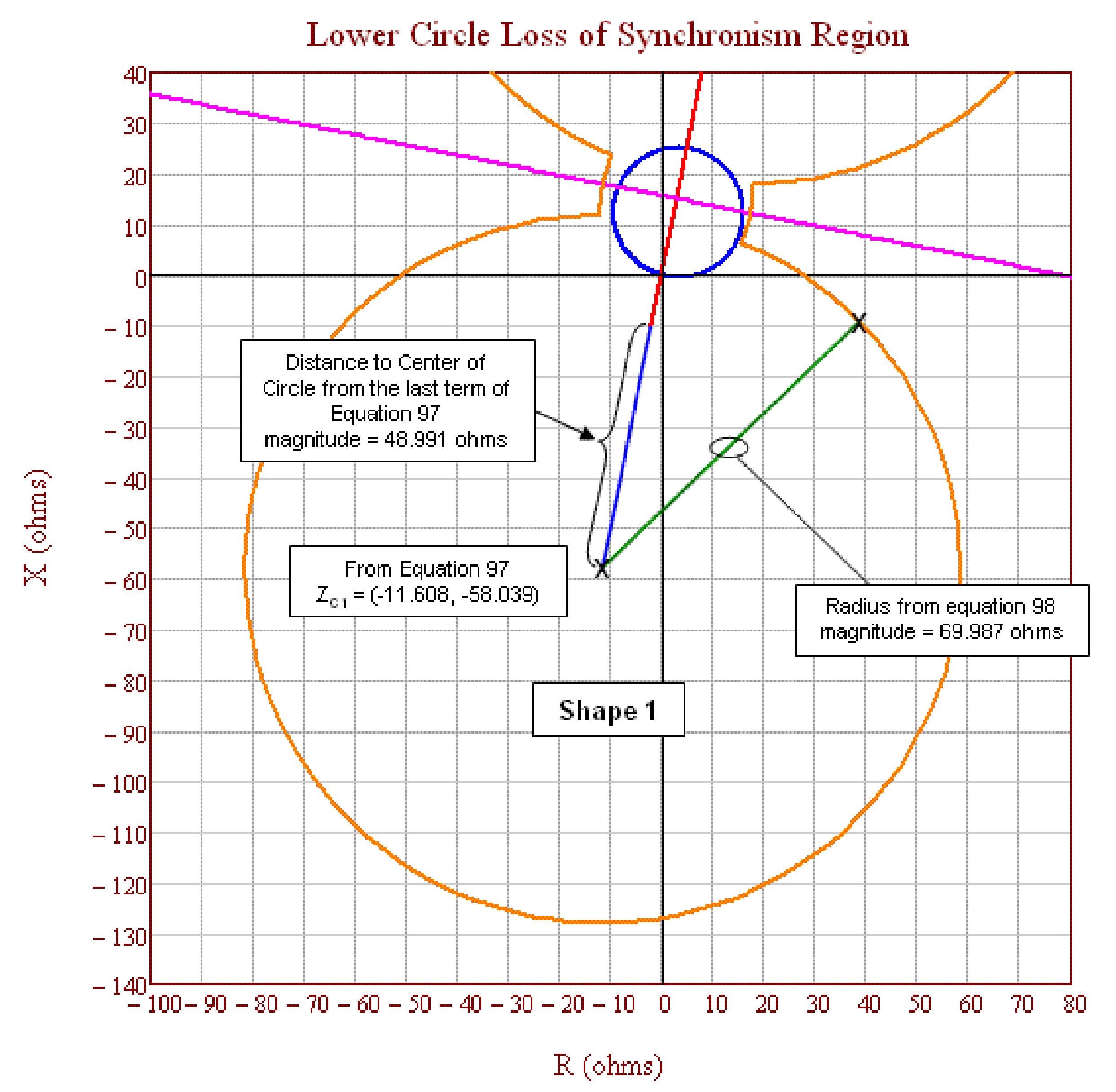


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

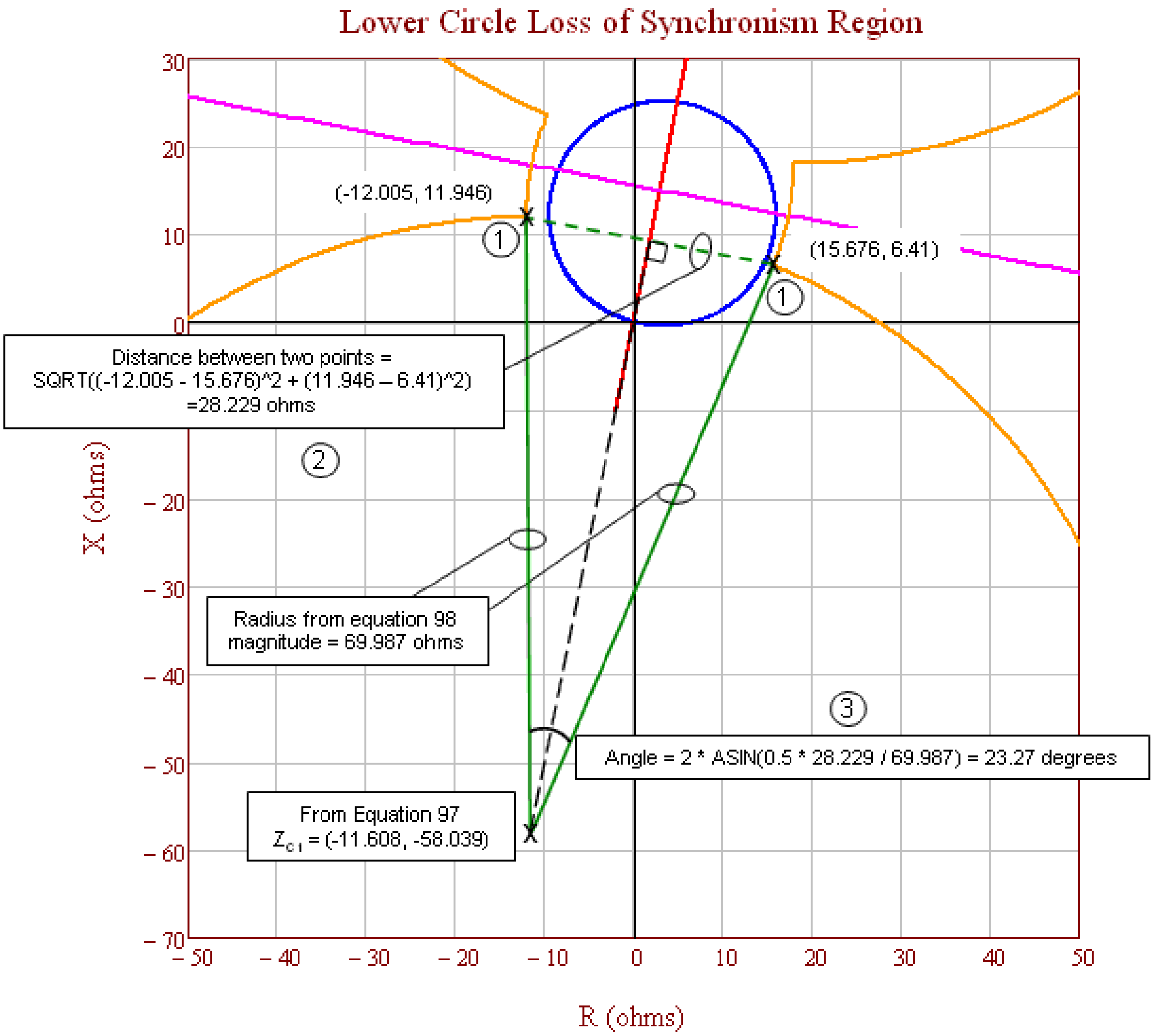


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

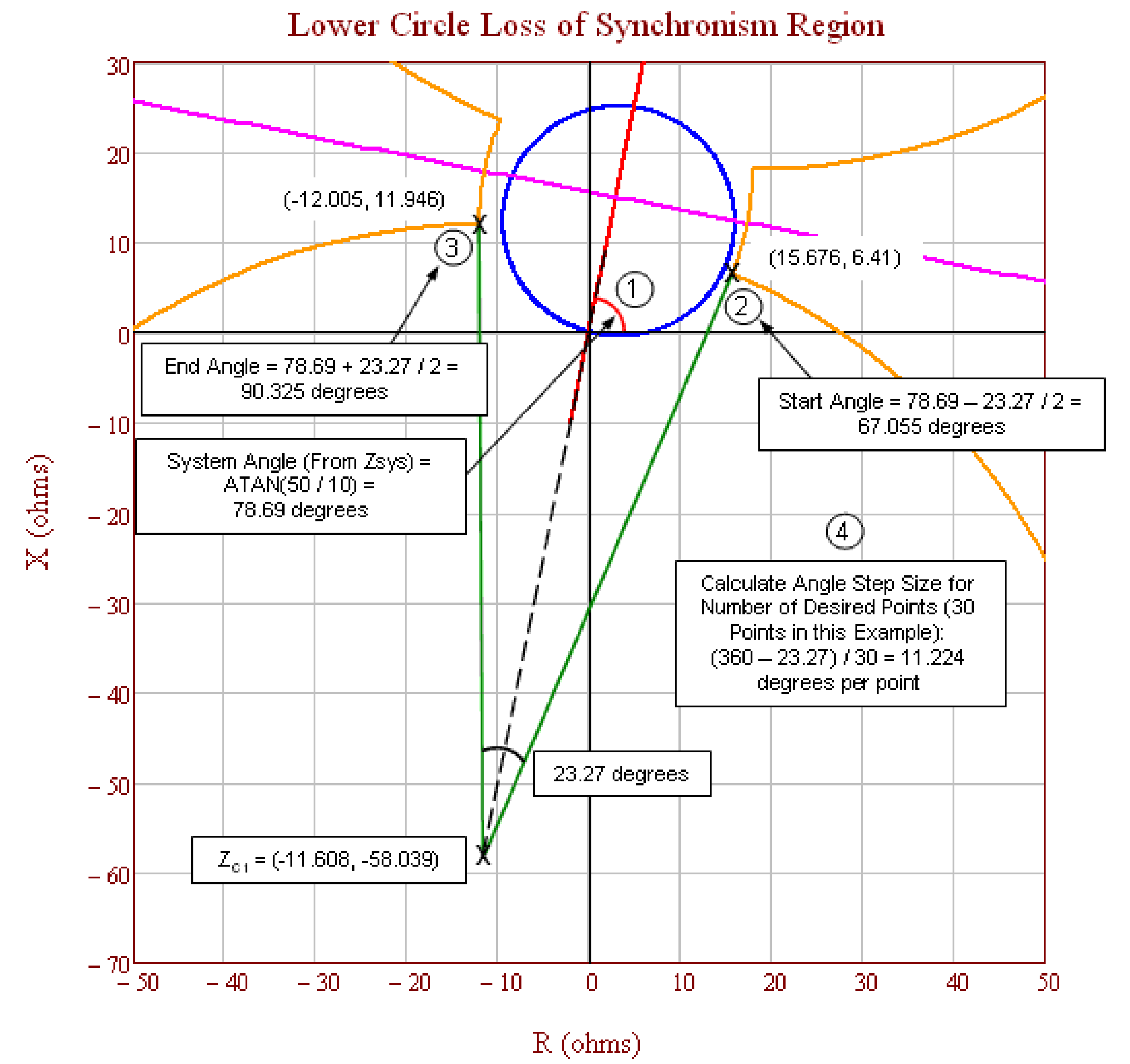


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

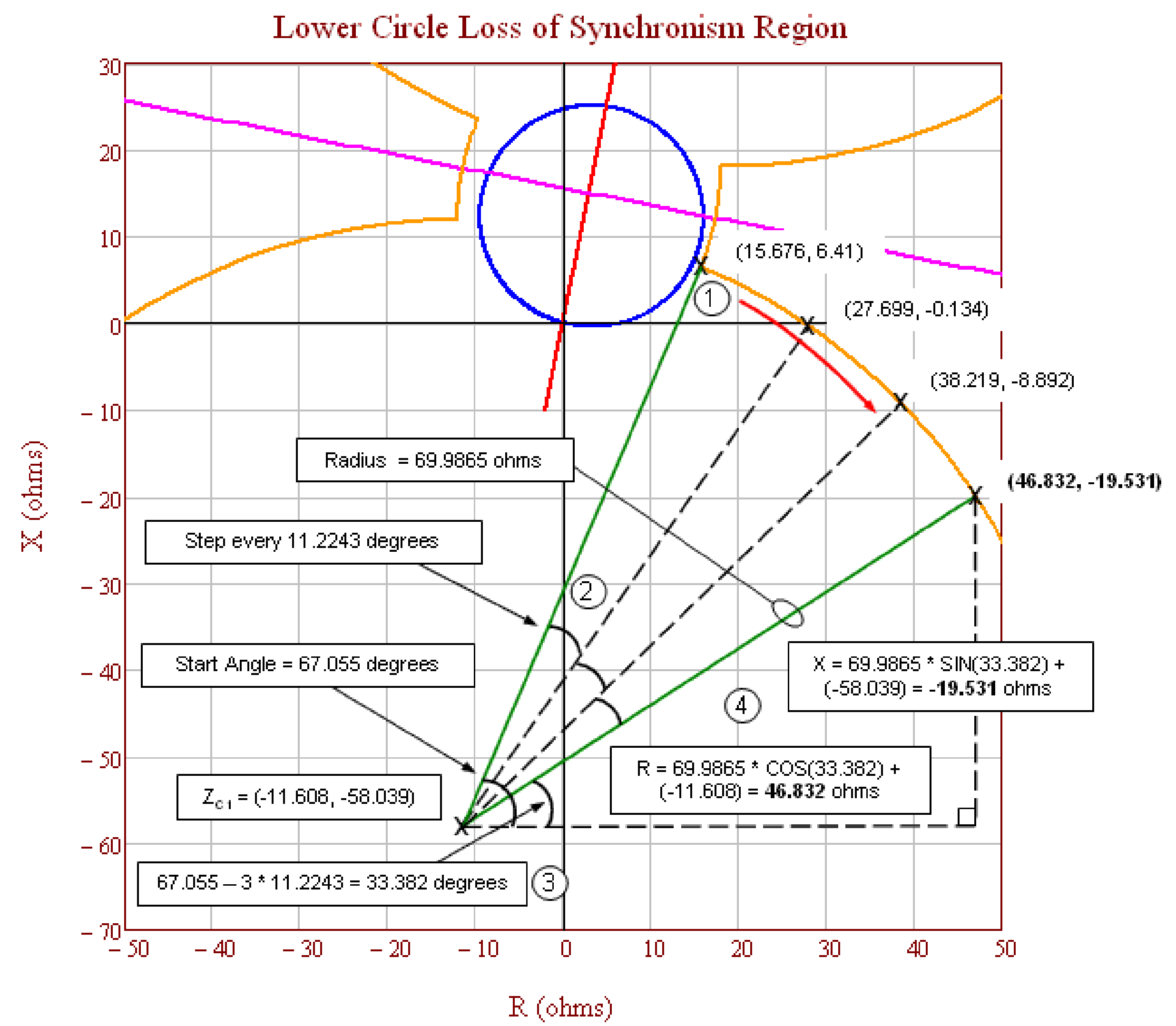


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

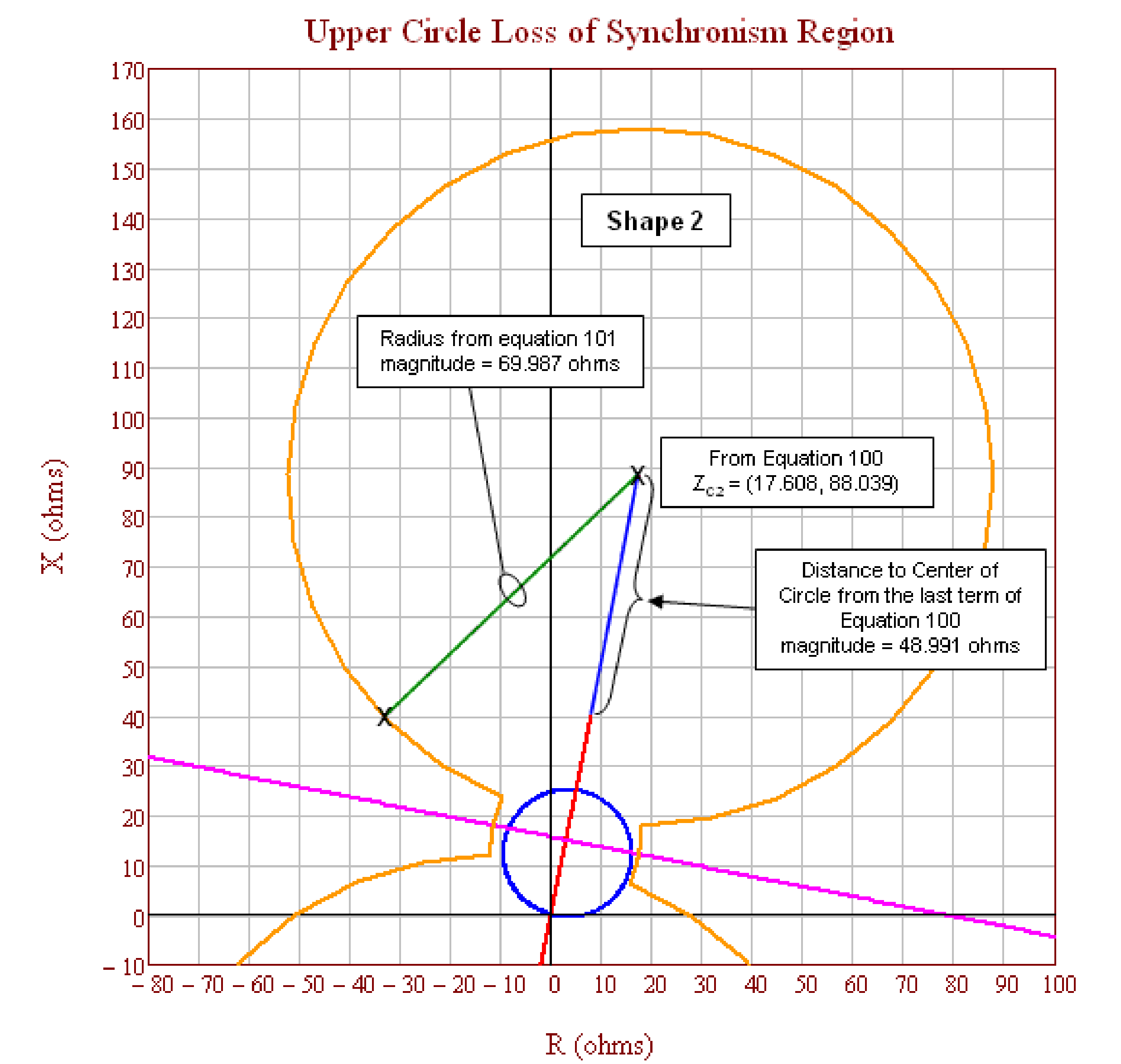


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

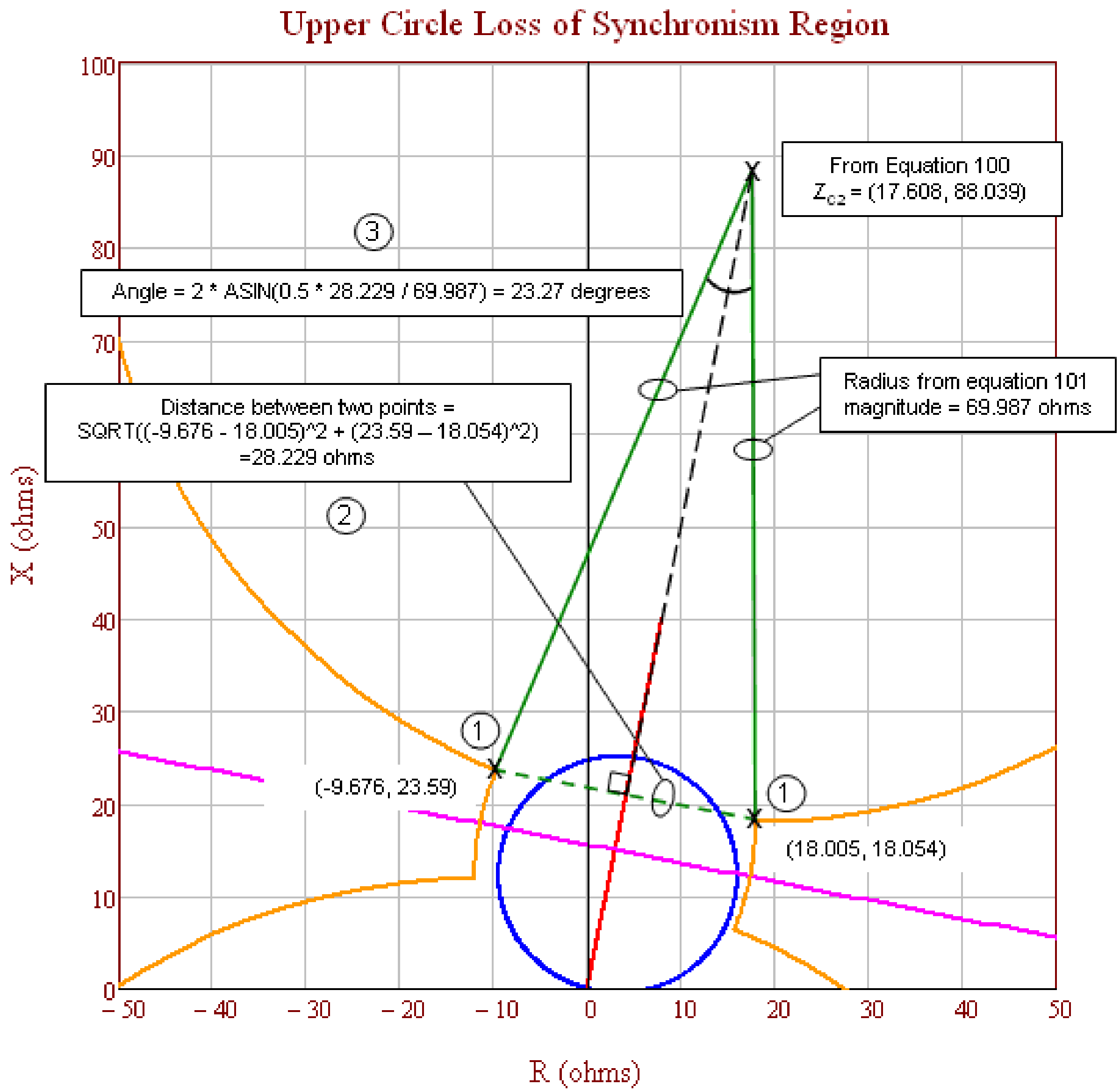


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

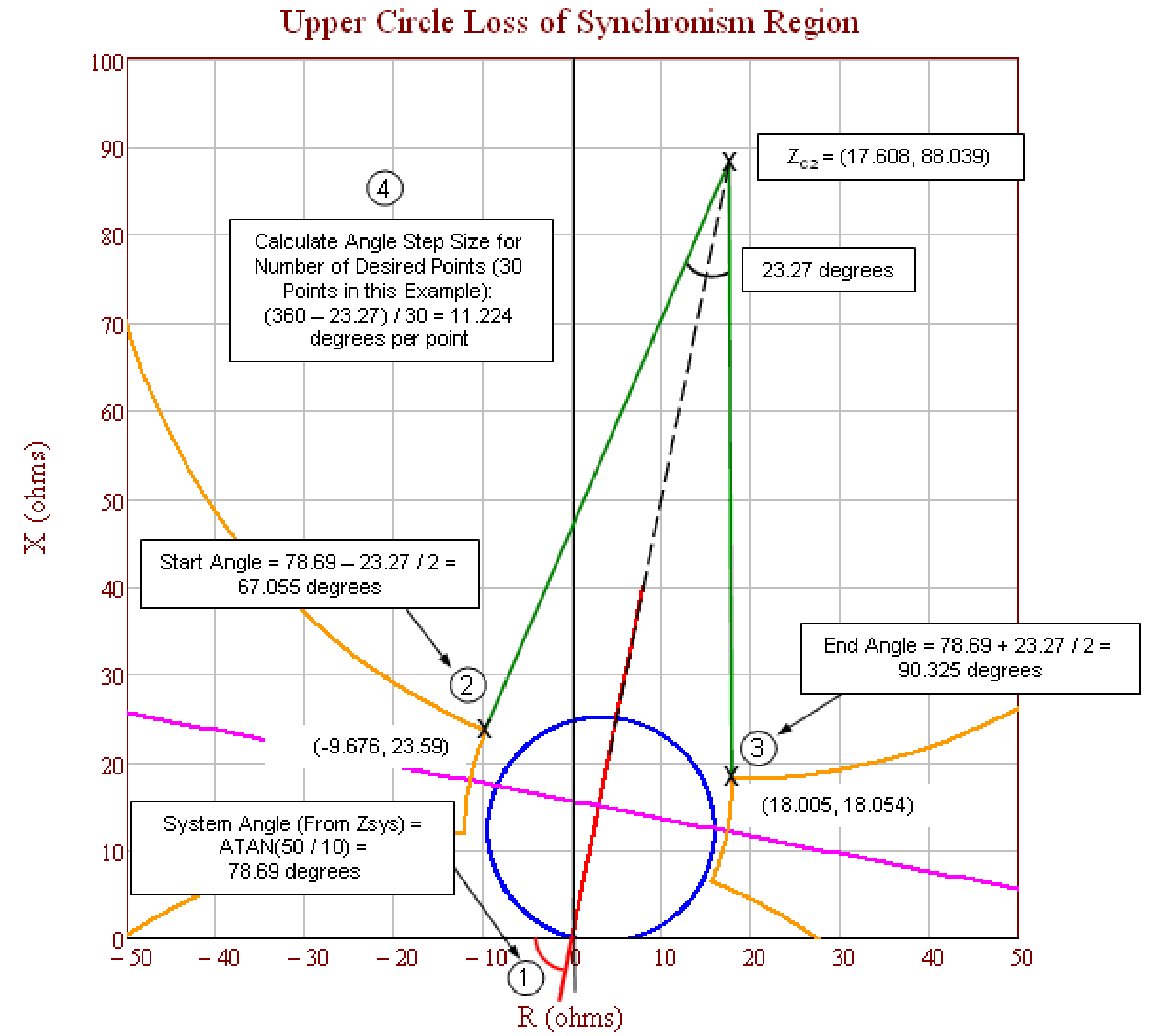


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

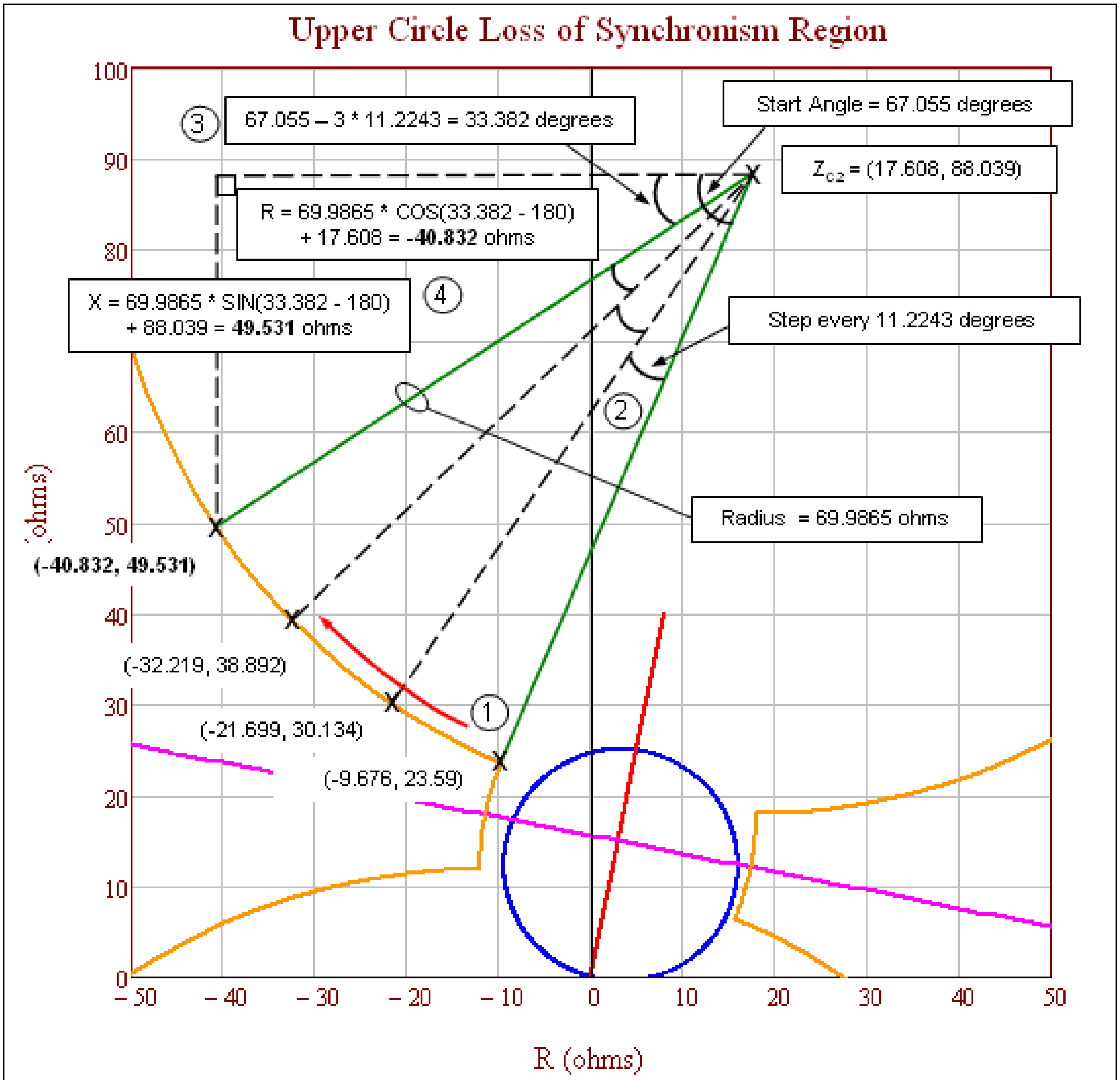


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates			Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX	Angle (degrees)	R	+ jX
67.055	15.676	6.41	67.055	-9.676	23.59
55.831	27.699	-0.134	55.831	-21.699	30.134
44.606	38.219	-8.892	44.606	-32.219	38.892
33.382	**46.832**	**-19.531**	**33.382**	**-40.832**	**49.531**
22.158	53.21	-31.643	22.158	-47.21	61.643
10.933	57.108	-44.765	10.933	-51.108	74.765
359.709	58.378	-58.395	359.709	-52.378	88.395
348.485	56.97	-72.011	348.485	-50.97	102.011
337.26	52.939	-85.092	337.26	-46.939	115.092
326.036	46.438	-97.139	326.036	-40.438	127.139
314.812	37.717	-107.69	314.812	-31.717	137.69
303.587	27.109	-116.341	303.587	-21.109	146.341
292.363	15.02	-122.762	292.363	-9.02	152.762
281.139	1.913	-126.707	281.139	4.087	156.707
269.914	-11.712	-128.026	269.914	17.712	158.026
258.69	-25.333	-126.667	258.69	31.333	156.667
247.466	-38.429	-122.682	247.466	44.429	152.682
236.241	-50.499	-116.225	236.241	56.499	146.225
225.017	-61.081	-107.542	225.017	67.081	137.542
213.793	-69.771	-96.965	213.793	75.771	126.965
202.568	-76.235	-84.899	202.568	82.235	114.899
191.344	-80.227	-71.806	191.344	86.227	101.806
180.12	-81.594	-58.185	180.12	87.594	88.185
168.895	-80.284	-44.56	168.895	86.284	74.56
157.671	-76.347	-31.45	157.671	82.347	61.45
146.447	-69.933	-19.357	146.447	75.933	49.357
135.222	-61.288	-8.744	135.222	67.288	38.744
123.998	-50.742	-0.016	123.998	56.742	30.016
112.774	-38.699	6.491	112.774	44.699	23.509
101.549	-25.62	10.53	101.549	31.62	19.47
90.325	-12.005	11.946	90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-~~1~~ 2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-~~1~~ 2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the

maximum power transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-~~1~~2 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

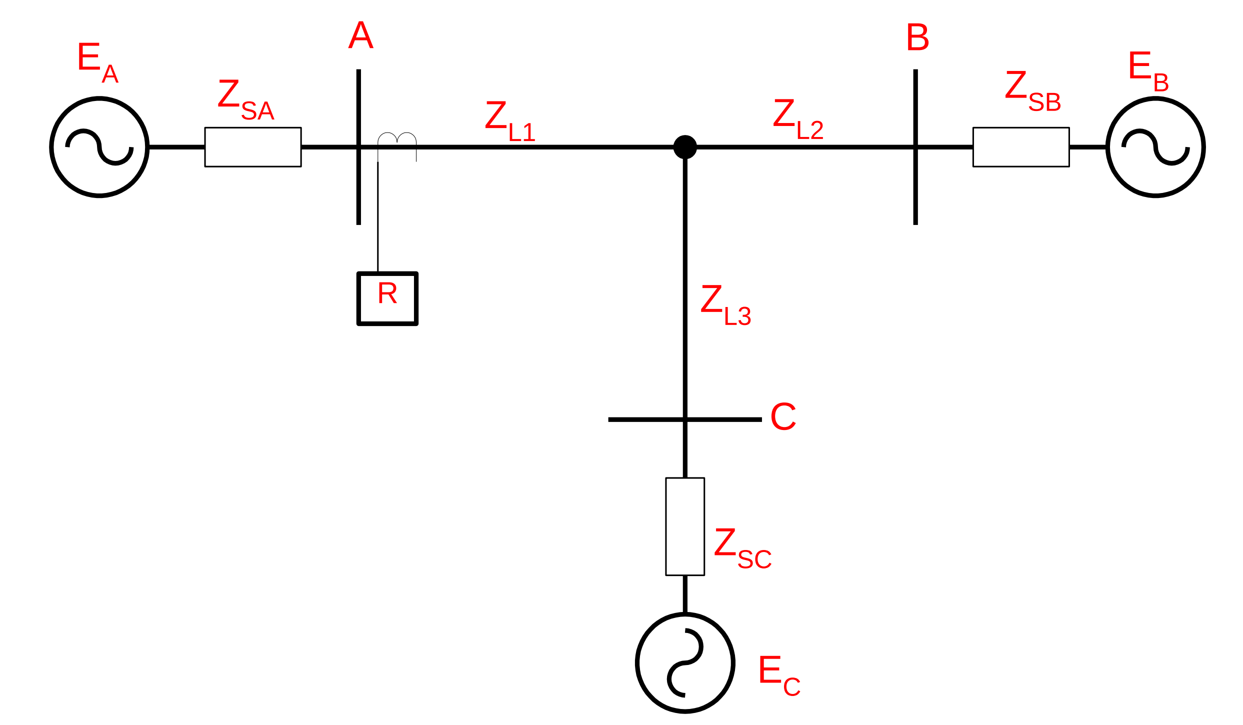


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

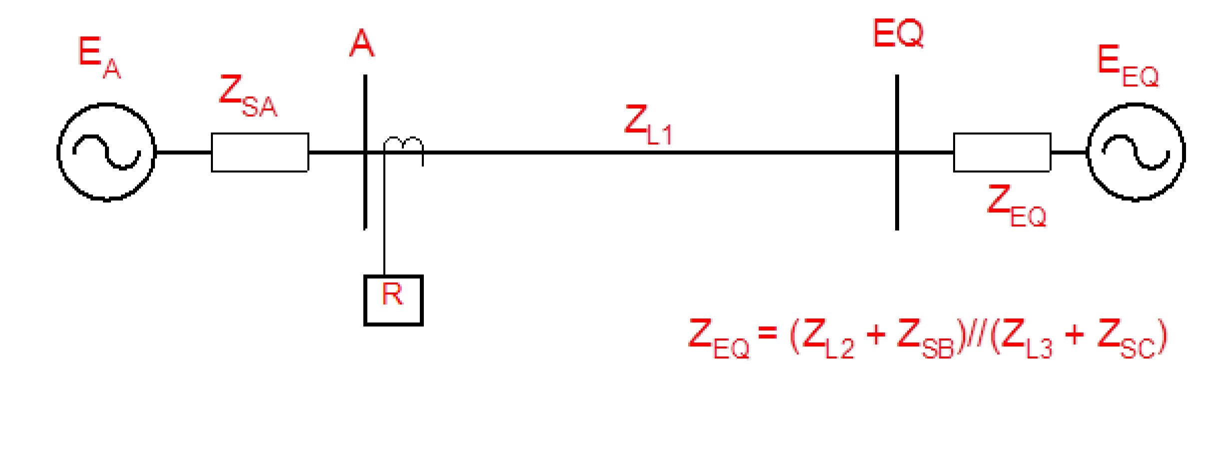


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-~~1~~2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

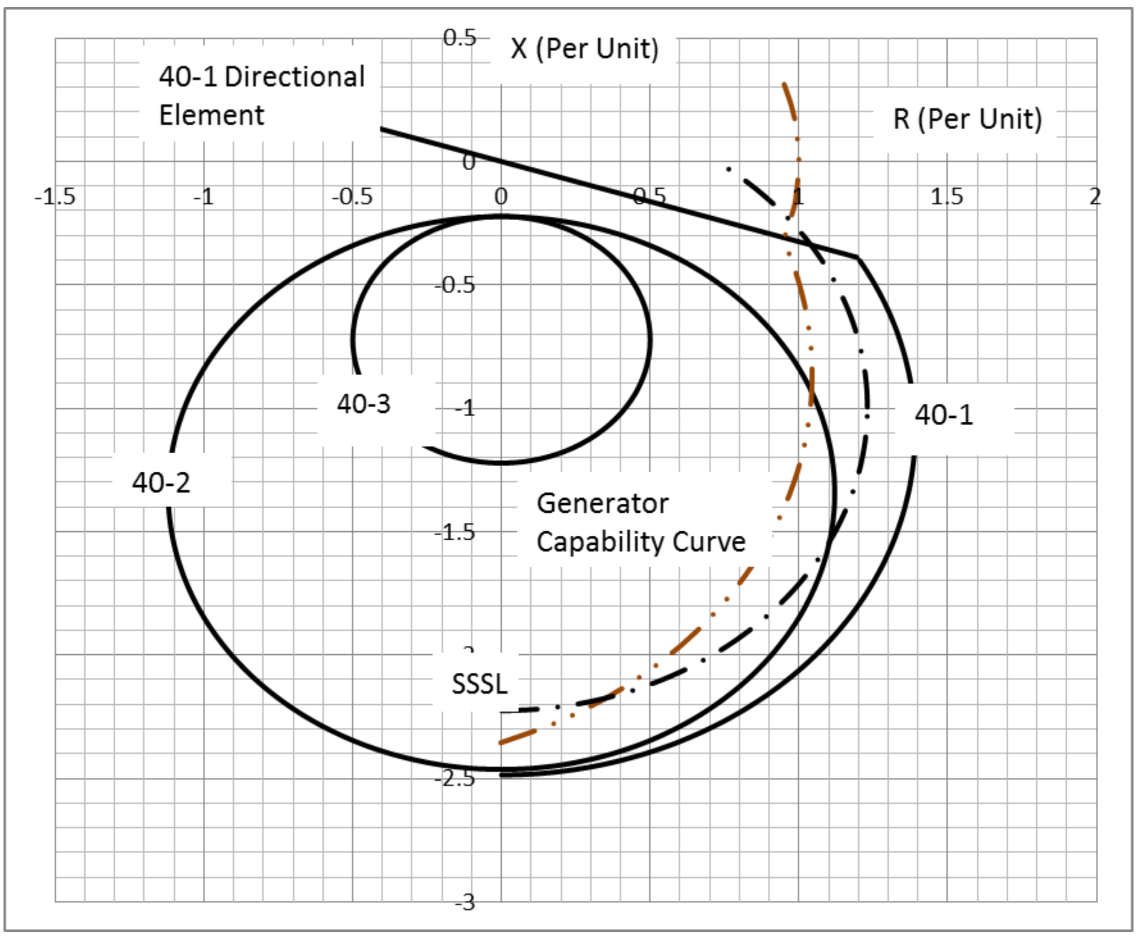


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-~~1~~2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-~~1~~2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

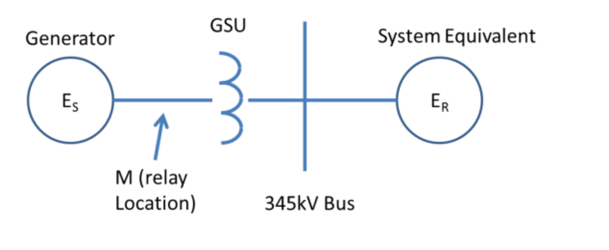

Figure 17: Simple one-line diagram of the system to be evaluated.

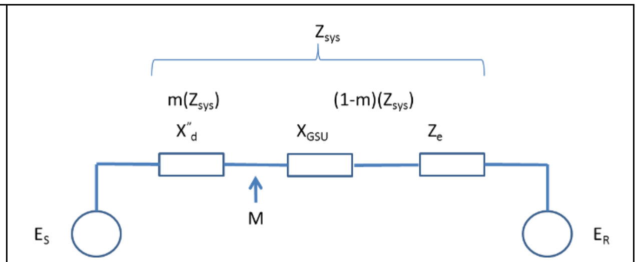

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[28] Ibid, Kimbark.

Table15: Example Data (Generator)		
50	I (pickup) = 5.0 per unit	
Transmission Owned Load-Responsive Protective Relays		
21-2	Diameter = 0.55 per unit	
	MTA = 85°	

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

Angle (δ) (Degrees)	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-~~1~~ 2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

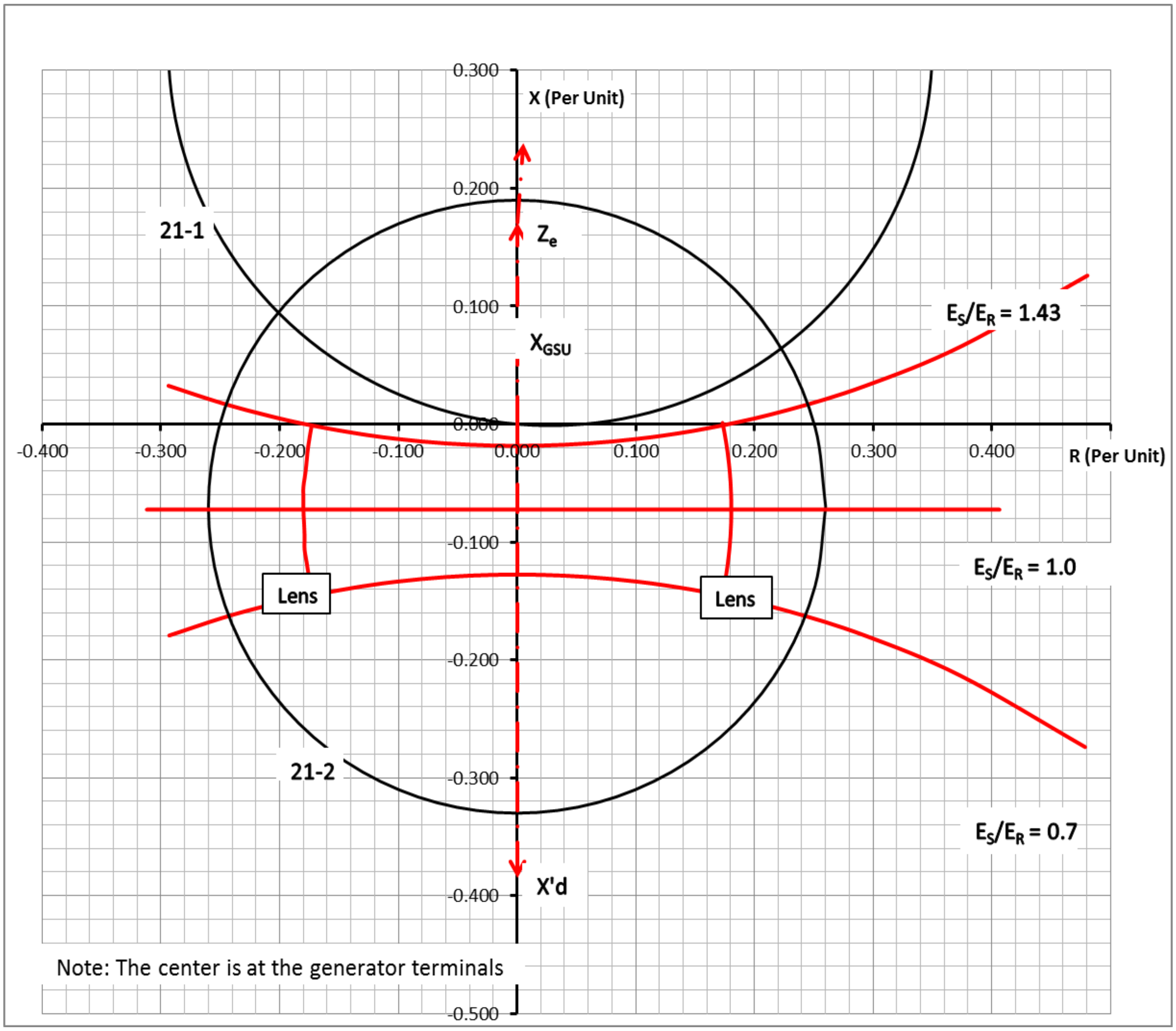

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

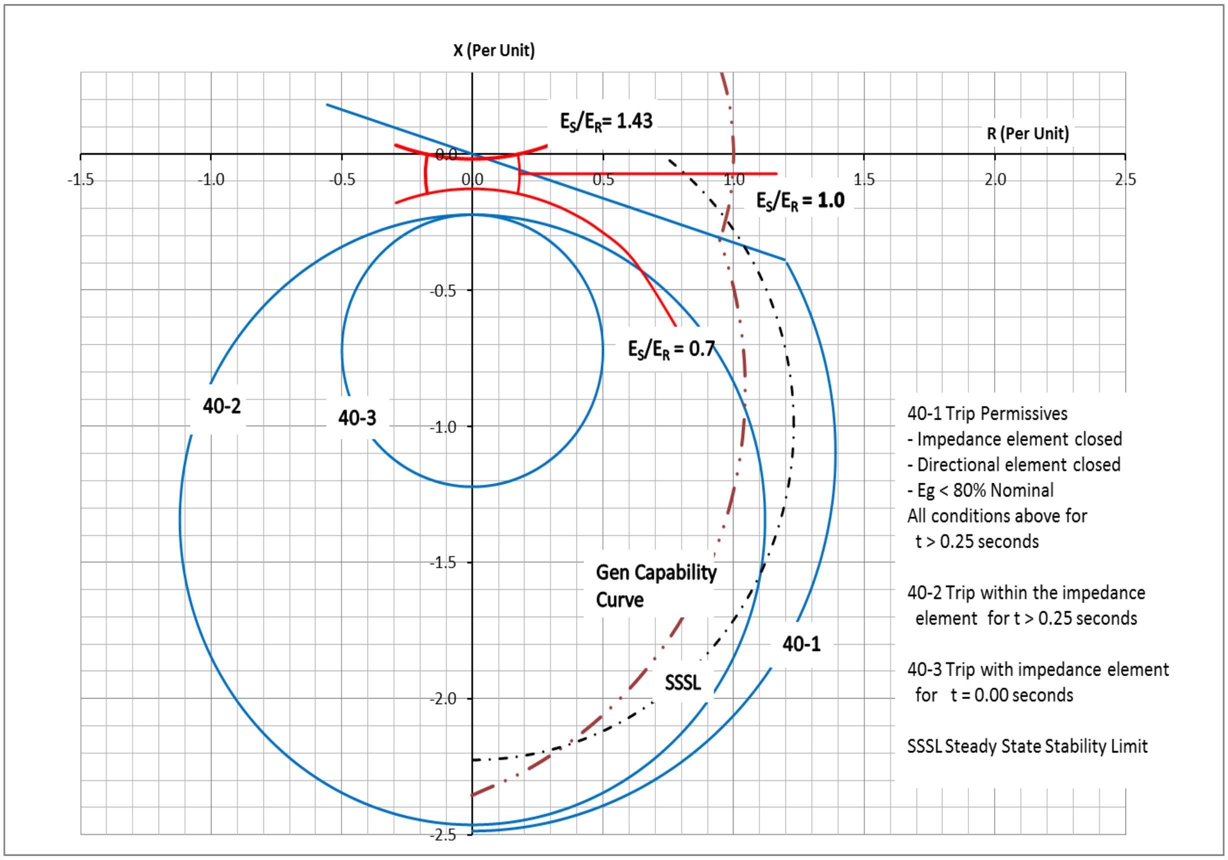

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-~~1~~2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-~~1~~2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150^\circ}{0.6239\angle 90^\circ} pu$$

$$I_{sys} = 2.91\ \angle 60^\circ\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-~~1~~ 2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer ($X_{T)}$, and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-~~1~~ 2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-~~1~~ 2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

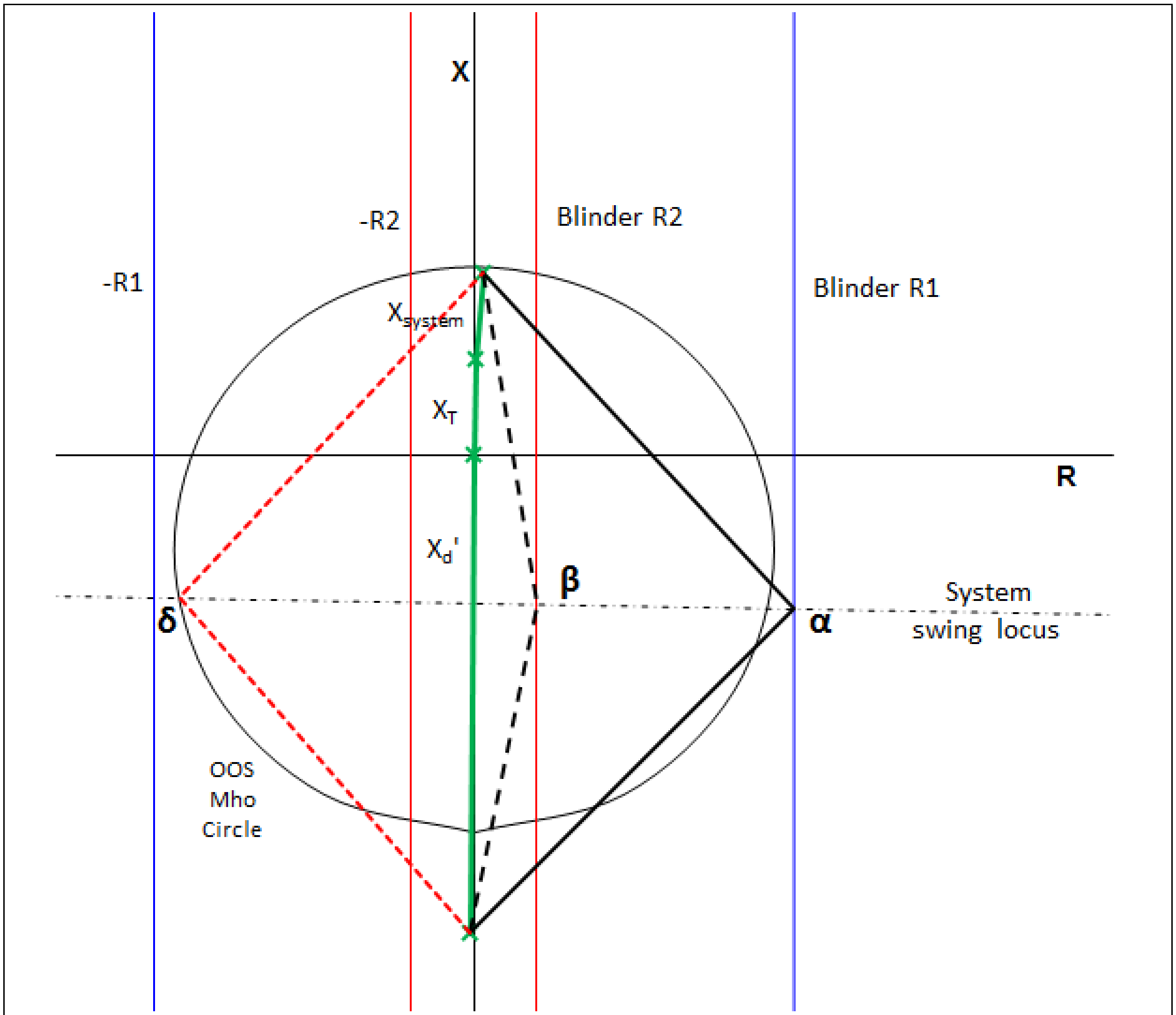

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

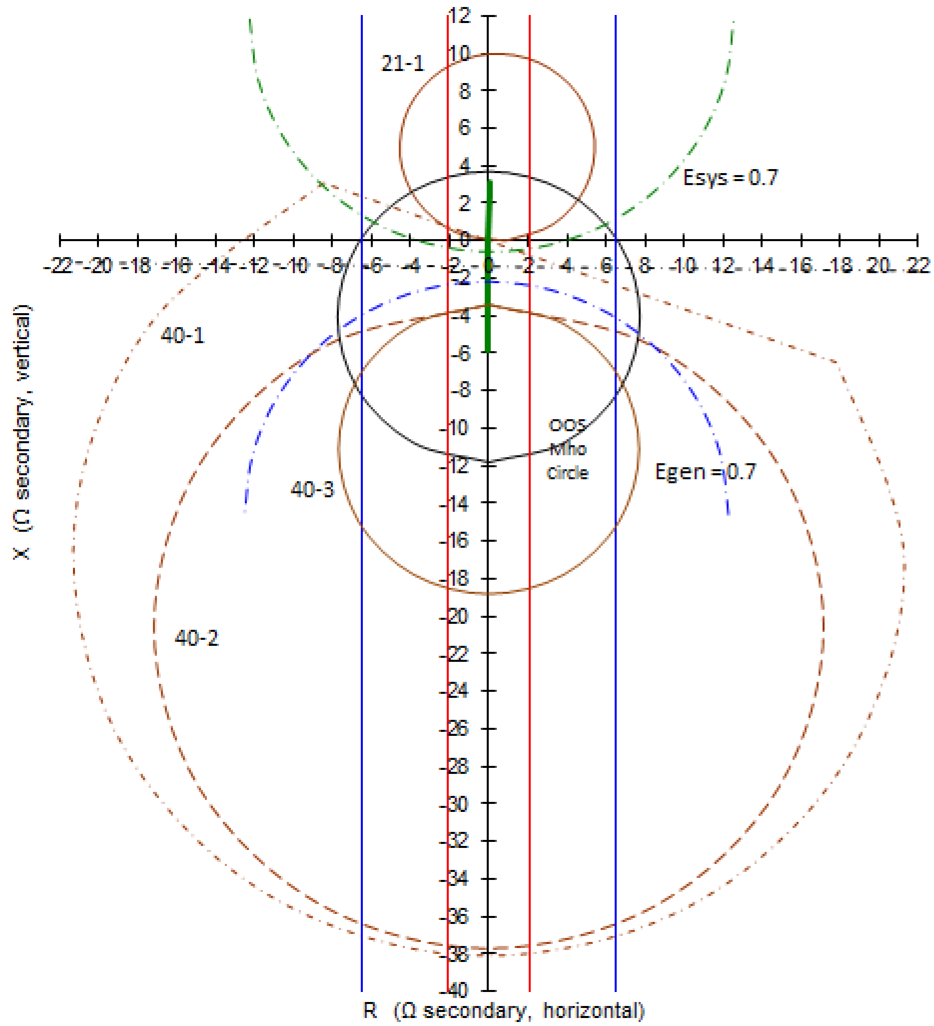

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-~~1~~2 – Attachment B criteria or can be excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-~~1~~2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-~~1~~2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-~~1~~2 – Attachment B criteria.

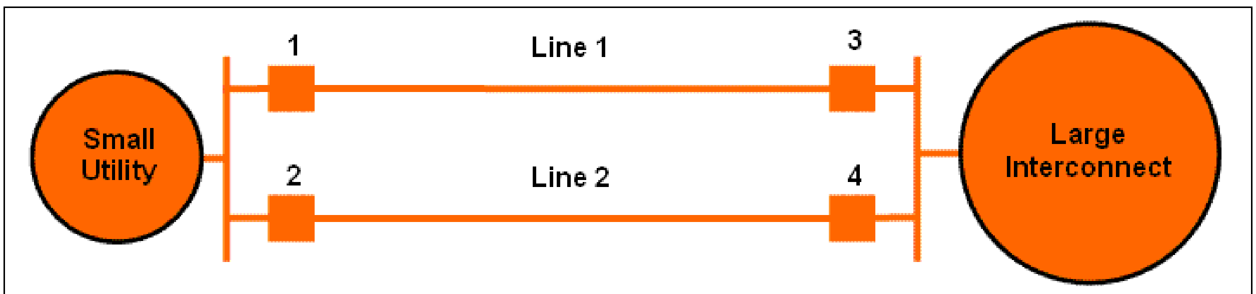

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

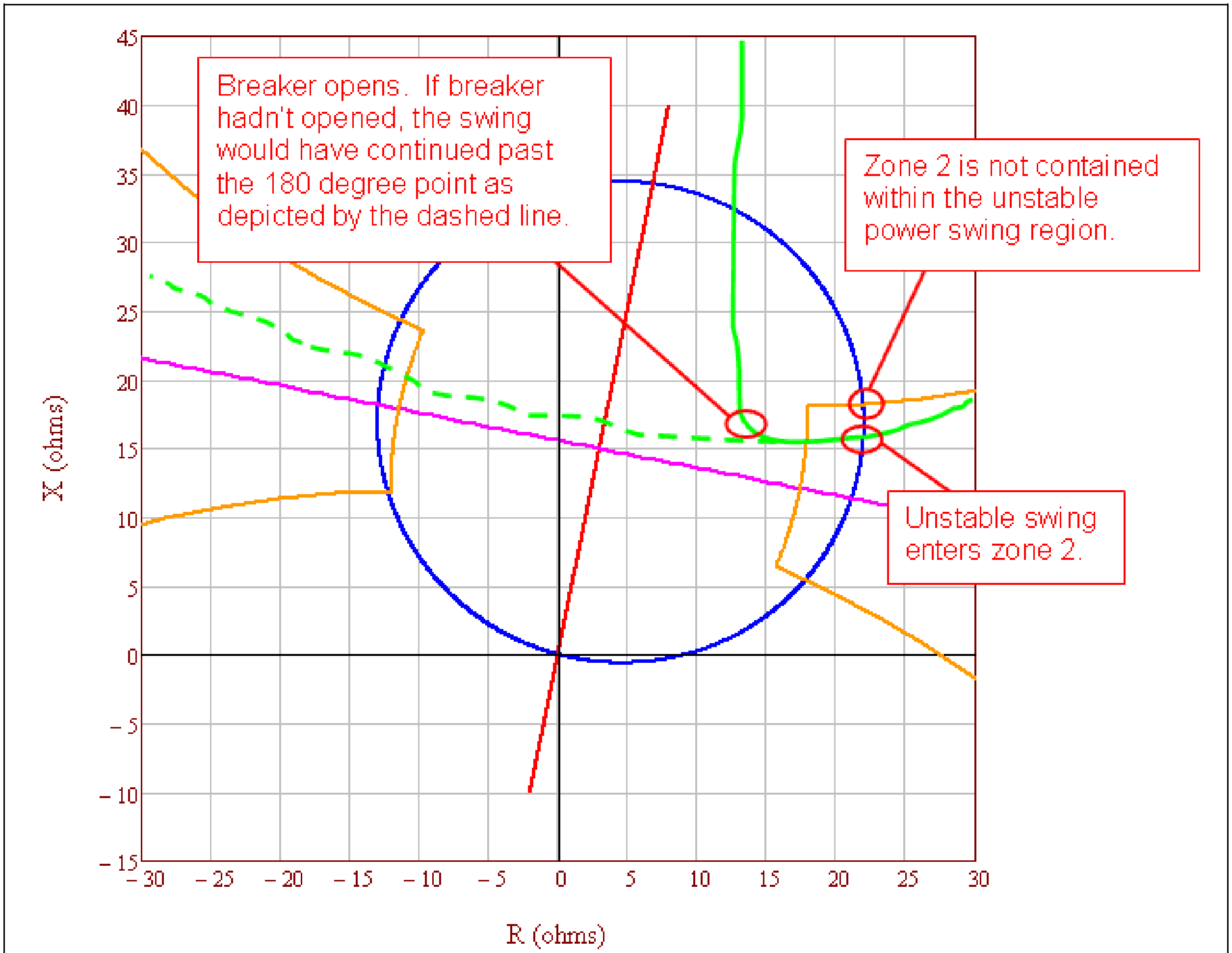

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-~~1~~2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

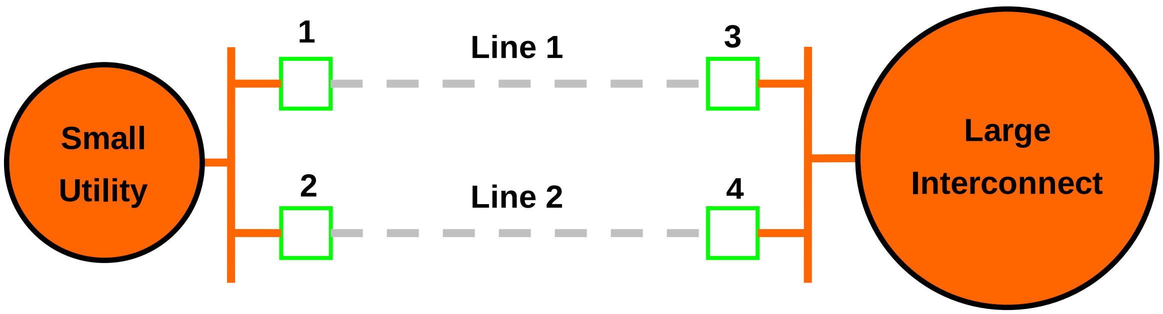

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

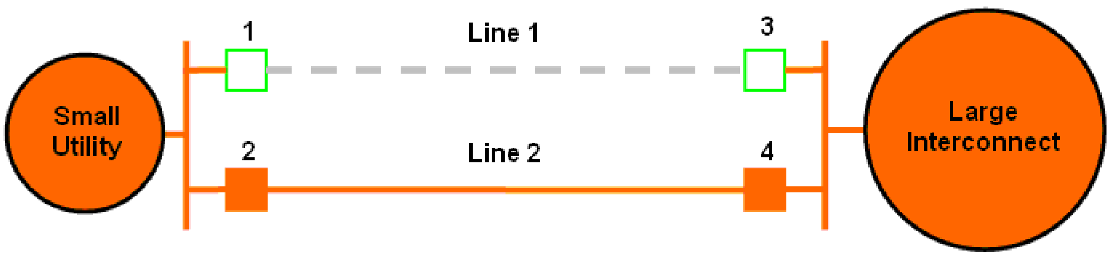

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

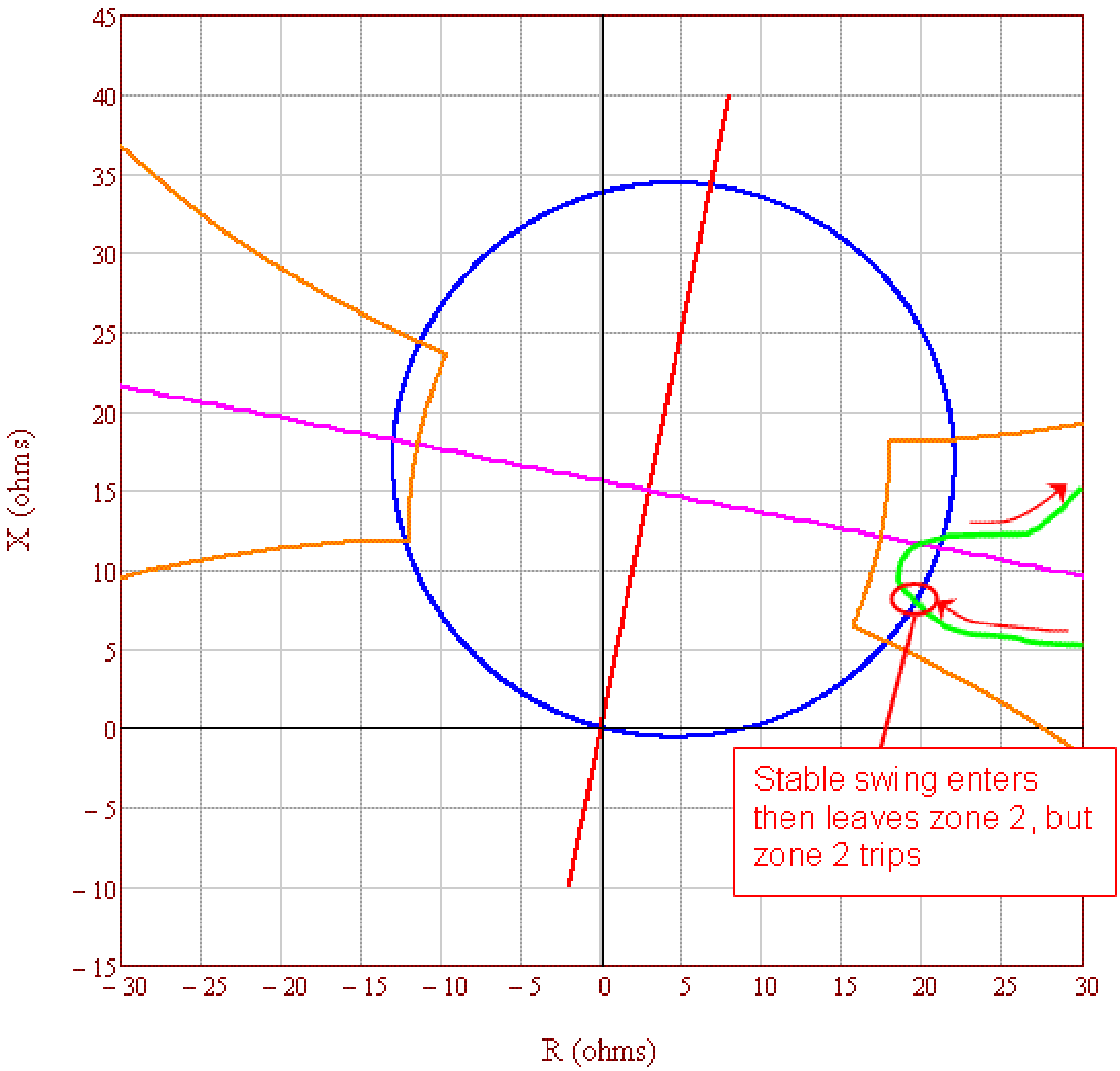

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-~~1~~2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

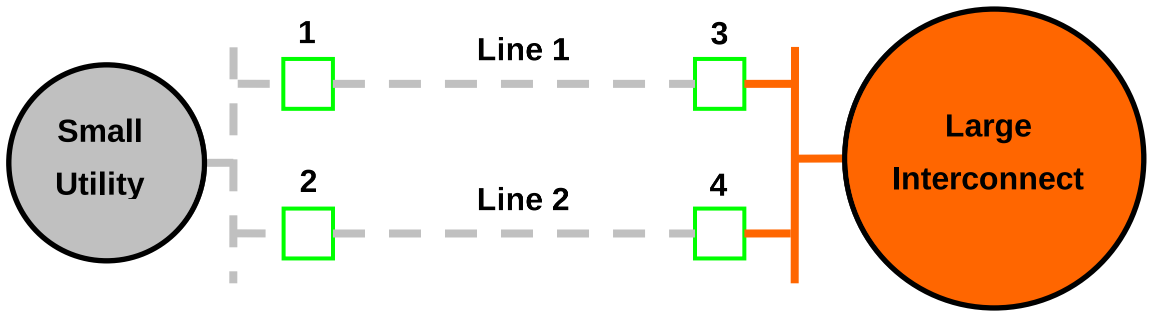

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-~~1~~2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-~~1~~2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-~~1~~2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-~~1~~2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	08/24/18 – 10/17/18
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-2~~1~~**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-~~1~~2 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates: See Implementation Plan

~~**Requirement R1**~~

~~First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**Requirements R2, R3, and R4**~~

~~First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, ~~exists~~ that is addressed by ~~a~~ limiting the output of a generator~~System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. ~~An~~ Elements associated with ~~that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an~~ angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event.~~constraint~~.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance for a planning event.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

~~[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.~~

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-~~1~~2 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-~~1~~2 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-~~1~~2 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-~~1~~2 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

Version	Date	Action	Change Tracking
2	TBD	Adopted by NERC Board of Trustees	Revised

PRC-026-~~1~~2 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., “load-responsive”) including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-~~1~~ 2 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-~~1~~ 2 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "~~PRC-026-1~~PRC-026-2") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-~~1~~2 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-~~1~~2 – Attachment B.

[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-~~1~~2 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-~~1~~2 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-~~1~~2 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-~~1~~2 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-~~1~~ 2 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., $E_S / E_R = 0.7 / 1.0 = 0.7$). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., $E_S / E_R = 1.0 / 0.7 = 1.43$). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-~~1~~ 2 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

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[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-~~1~~2 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-~~1~~2 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-~~1~~2 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-~~1~~2 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-~~1~~2 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

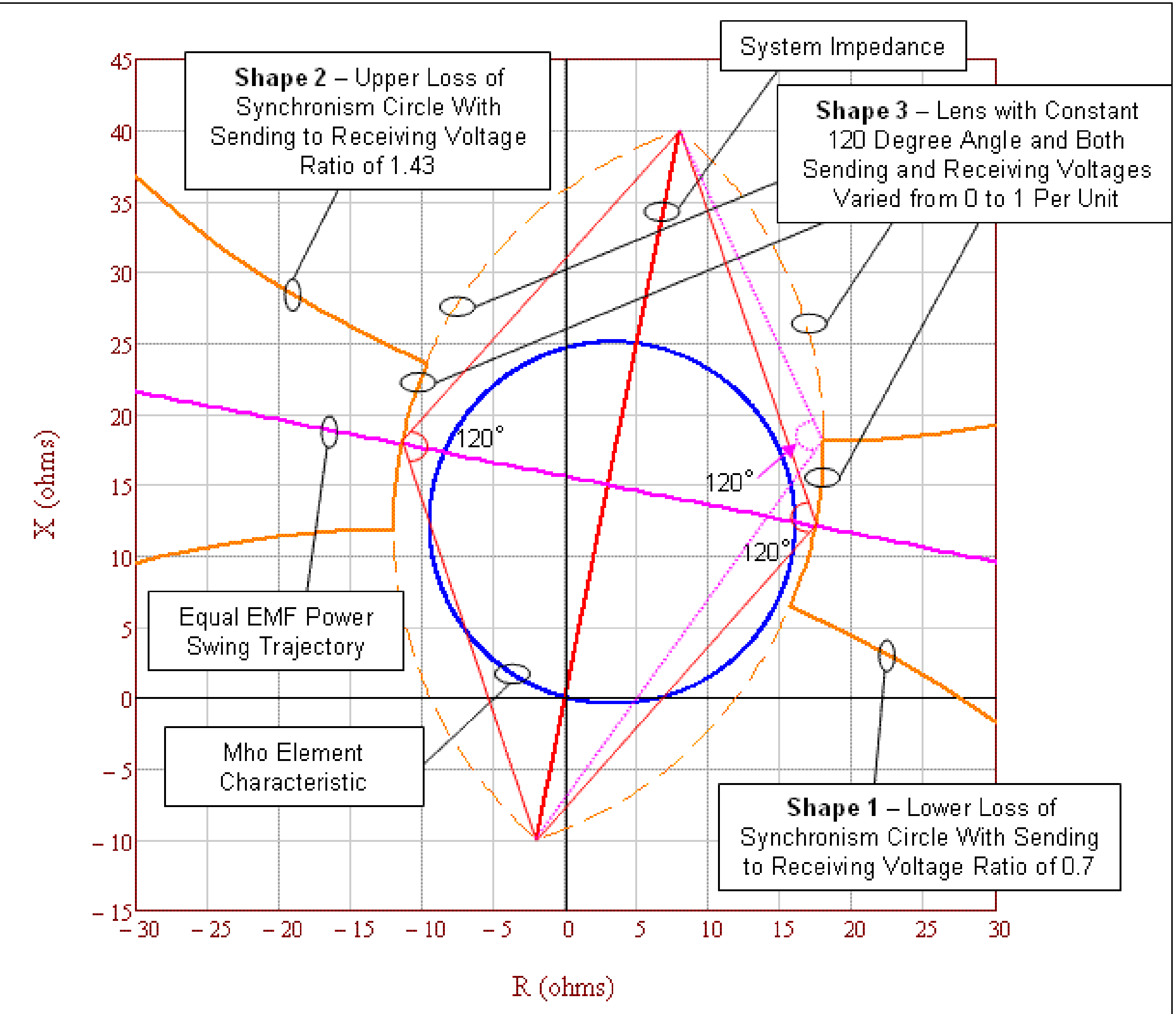


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-~~1~~2 – Attachment B, Criterion A, No. 1.

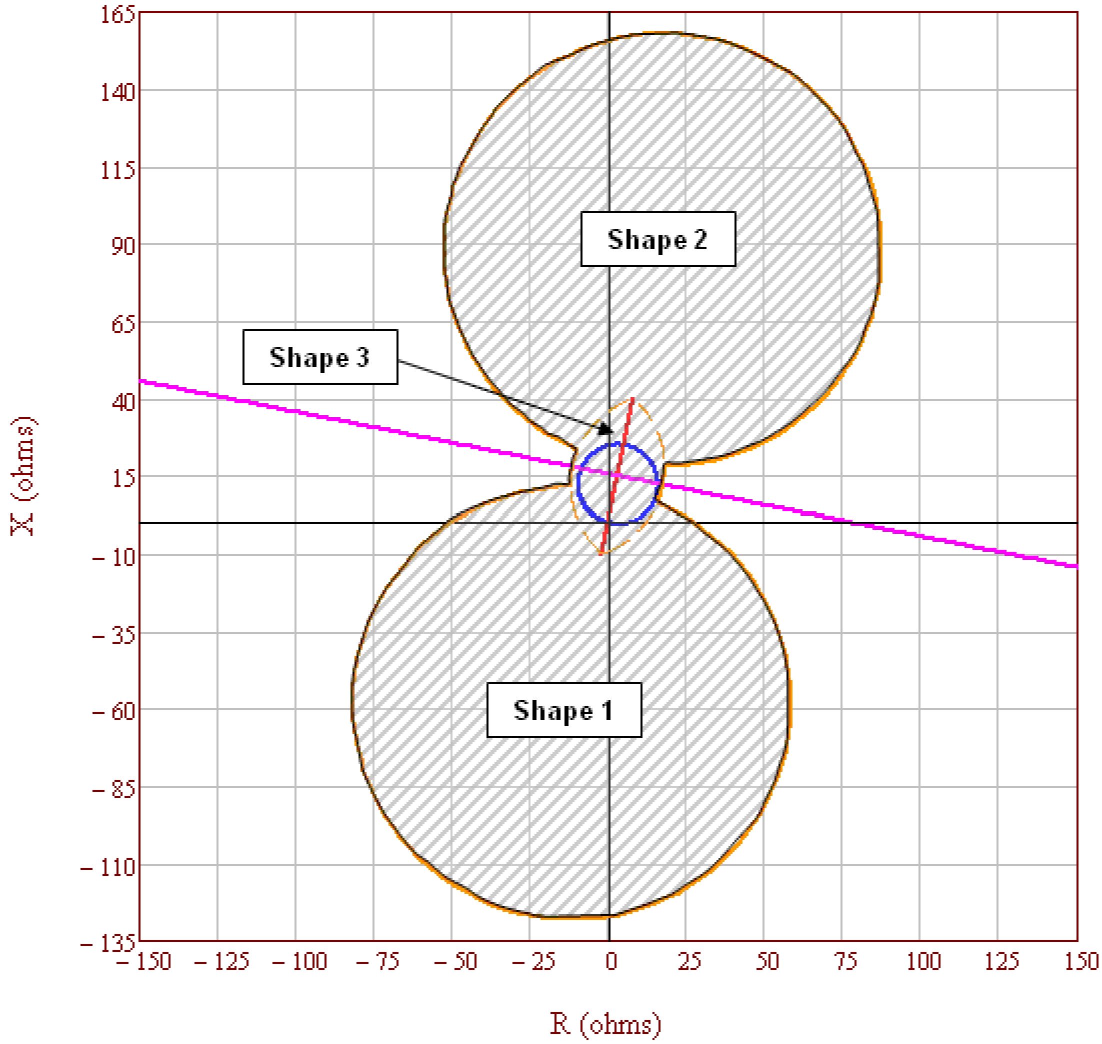


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

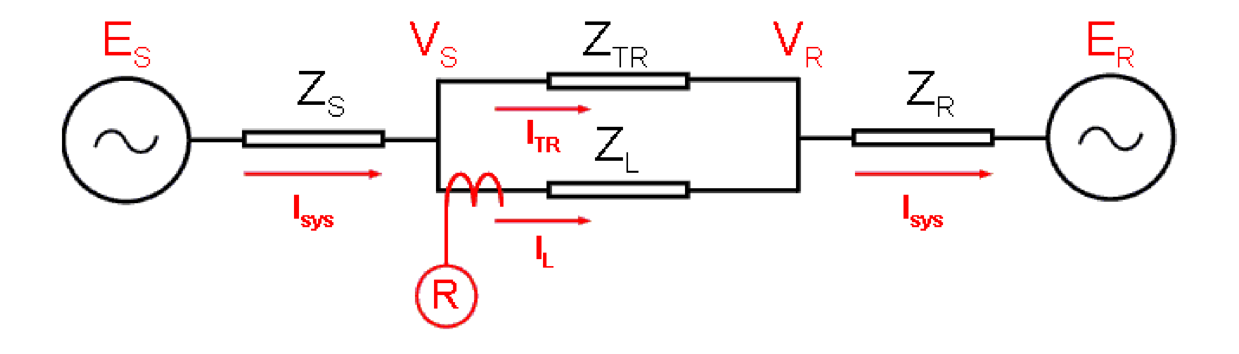


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

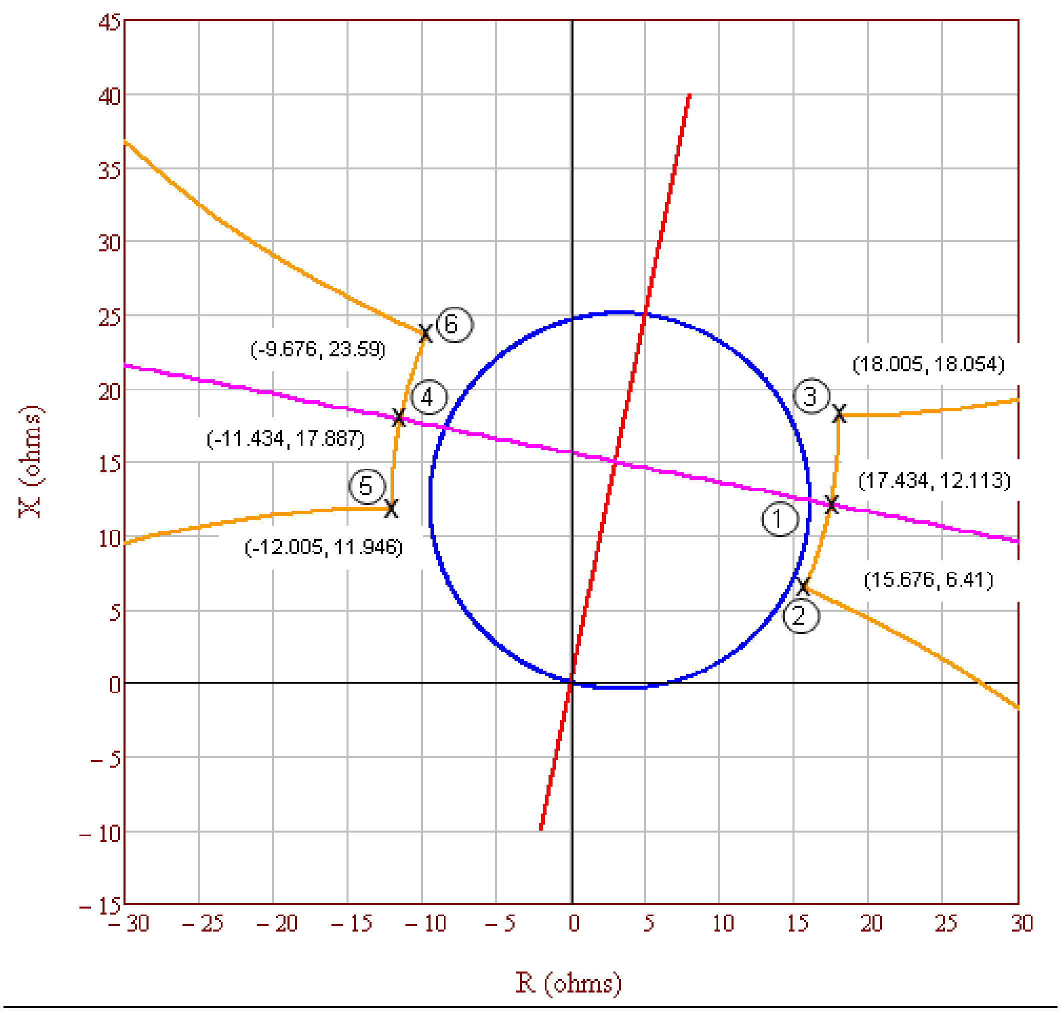


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3°\ A \times \dfrac{(4+j20)\times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20)\times 10^{10}\ \Omega}$
	$I_L = 4{,}511\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\big((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\big)}{\big((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\big)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2+j10)\ \Omega + (4+j20)\ \Omega + (4+j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10+j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \dfrac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \big(Z_S \times I_{sys}\big)$
	$V_S = 92{,}953\angle 120°\ V - [(2+j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99^\circ\ V}{3{,}854\angle 77^\circ\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120^\circ}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120^\circ\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120^\circ\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0^\circ}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0^\circ\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0^\circ\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

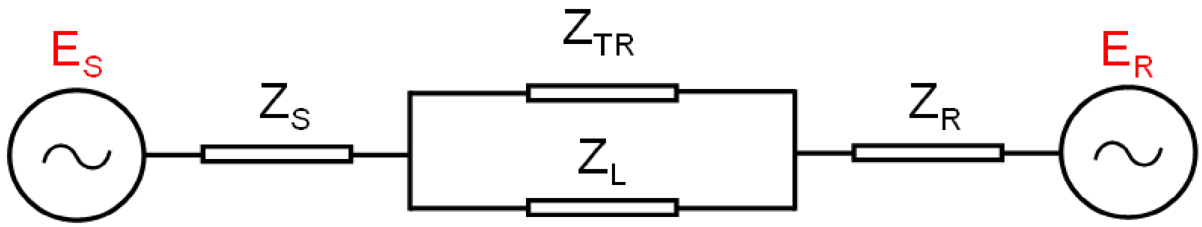
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1°\, A]$
	$V_S = 95{,}756\angle -106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1°\, V}{4{,}511\angle 131.1°\, A}$
	$Z_{L-Relay} = -11.434 + j17.887\,\Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240°\, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\,\Omega$	$Z_L = 4 + j20\,\Omega$	$Z_R = 4 + j20\,\Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\,\Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

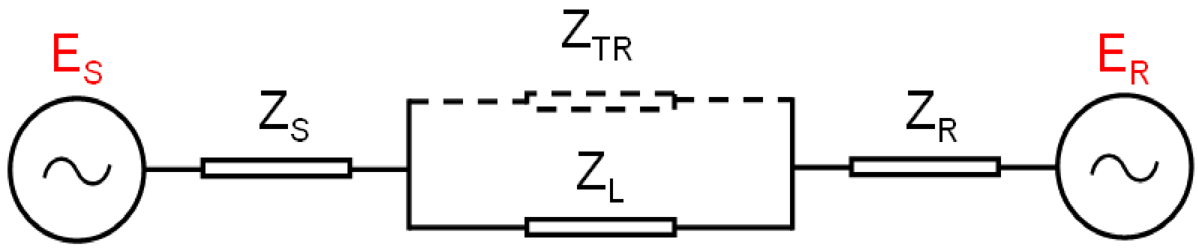
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle -110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

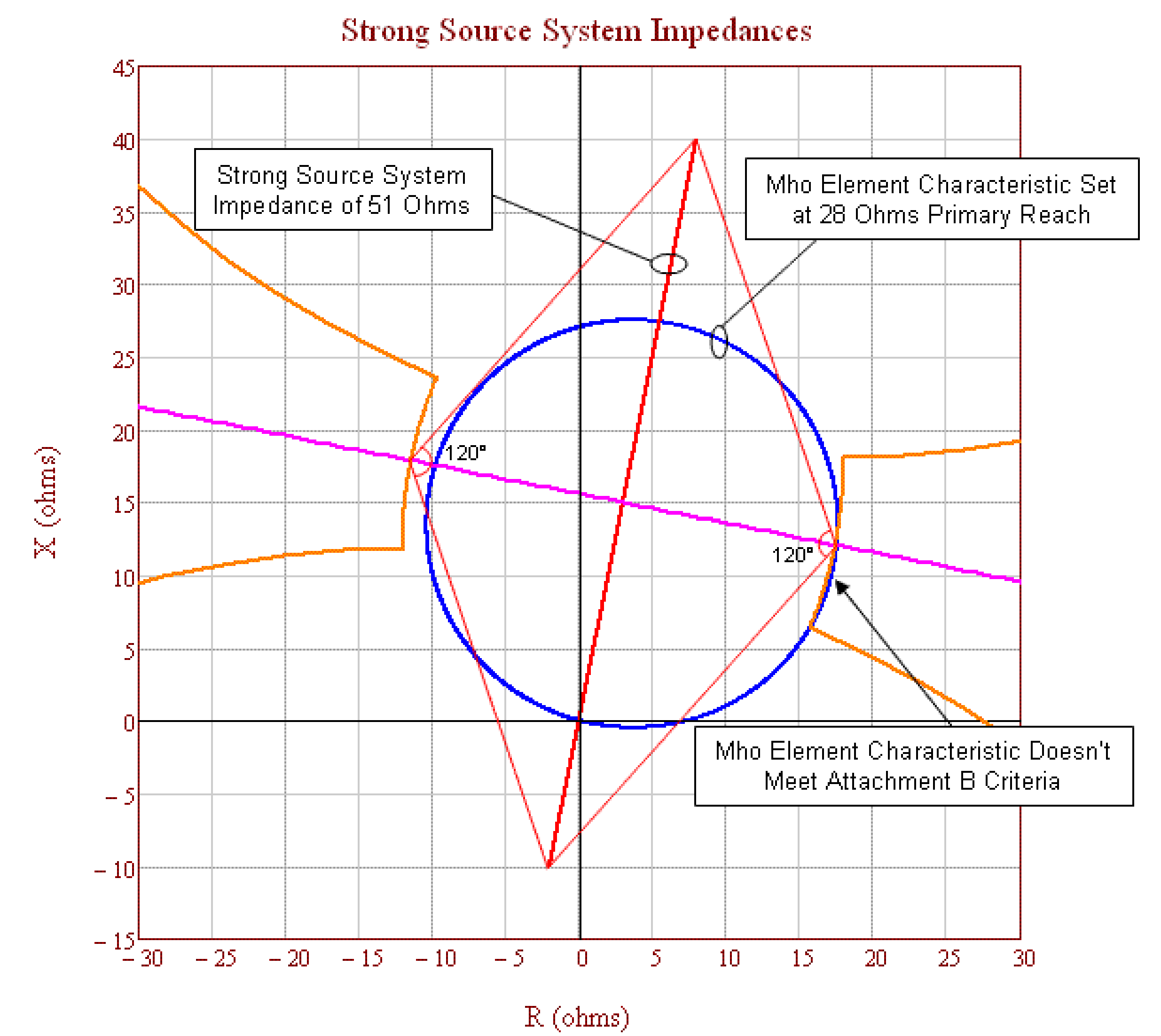


Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-~~1~~2 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

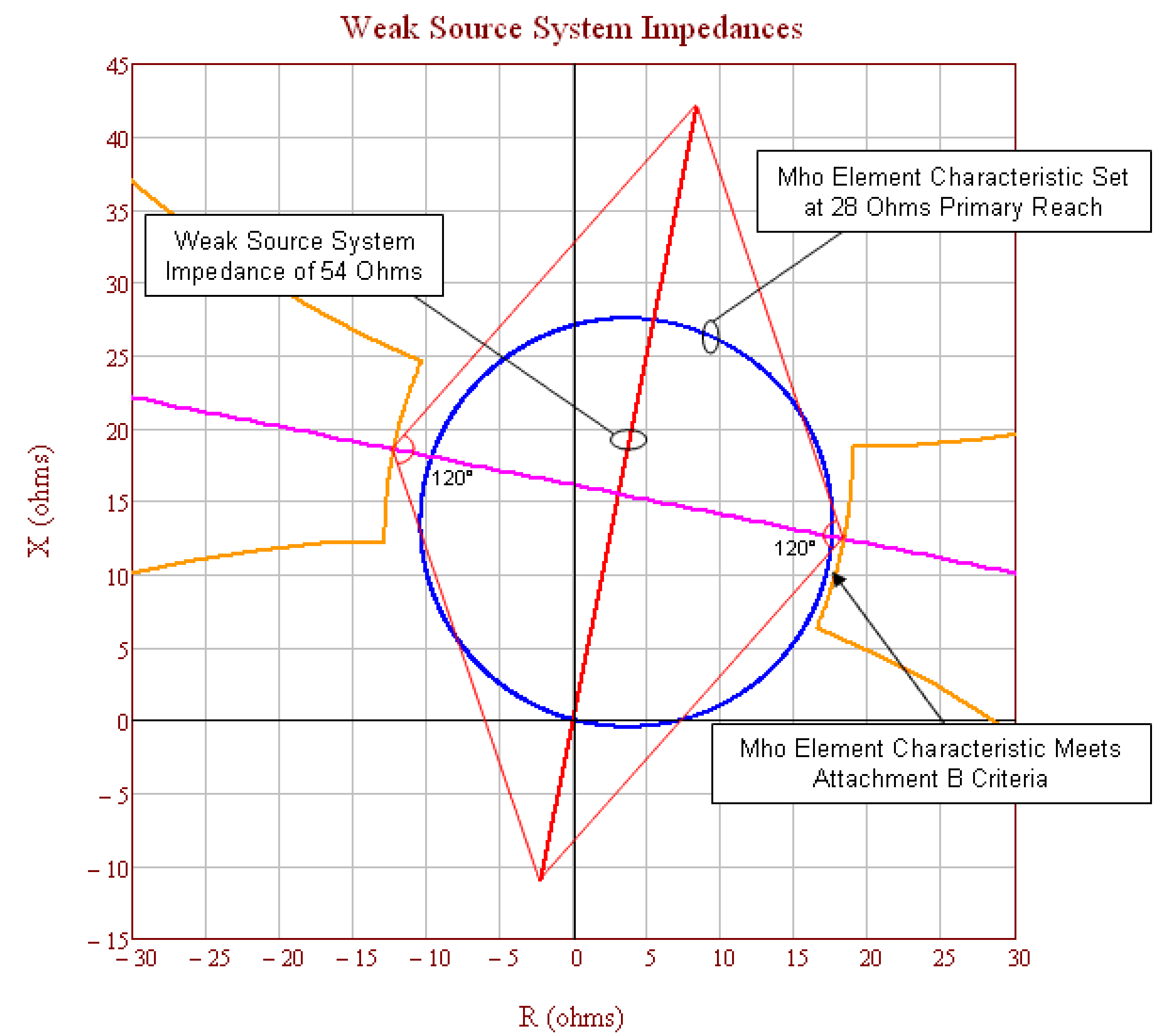


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

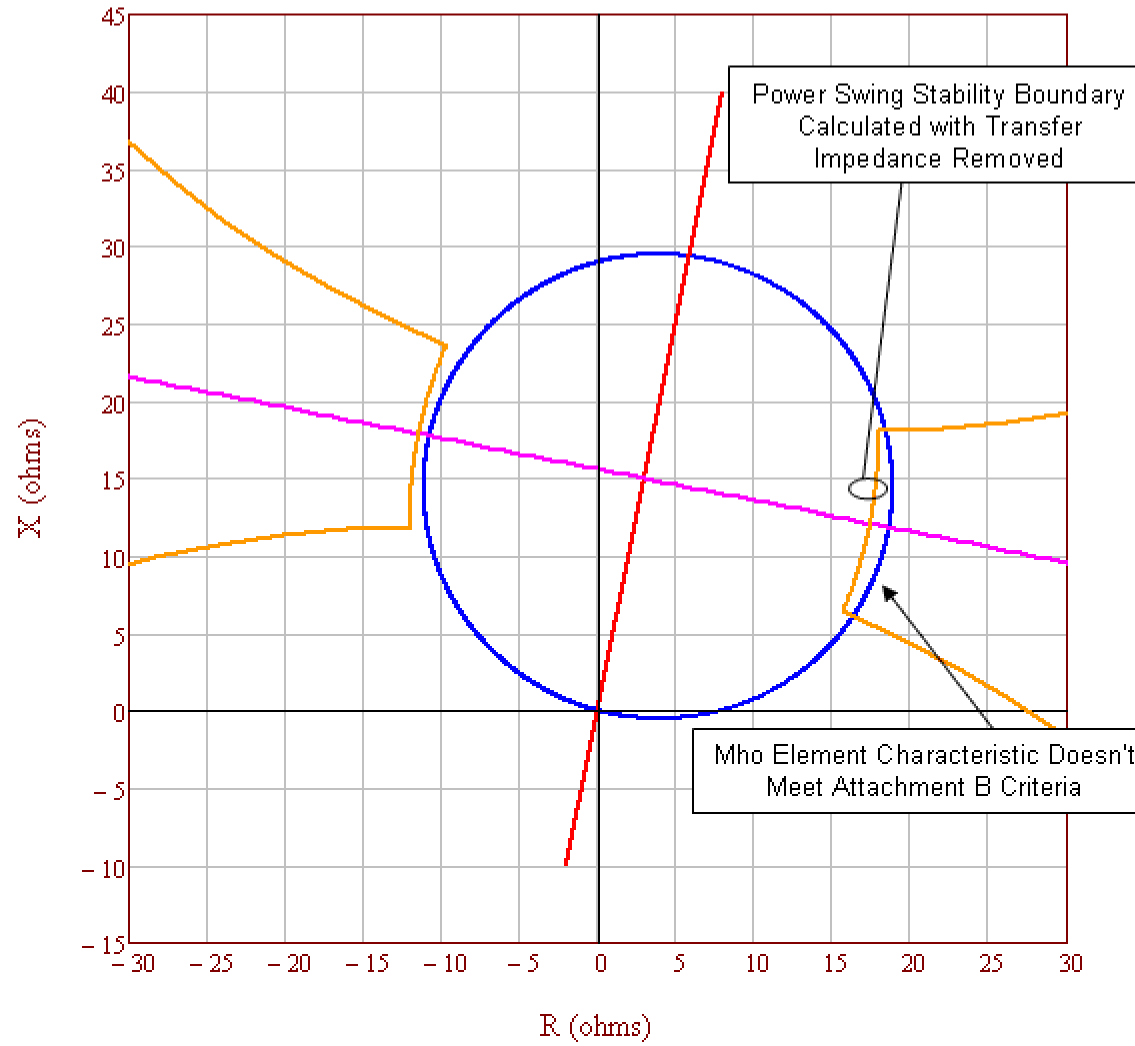


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-~~1~~2 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\, A]$
	$V_S = 95{,}757\angle 106.1°\, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\, V}{4{,}511\angle 71.3°\, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

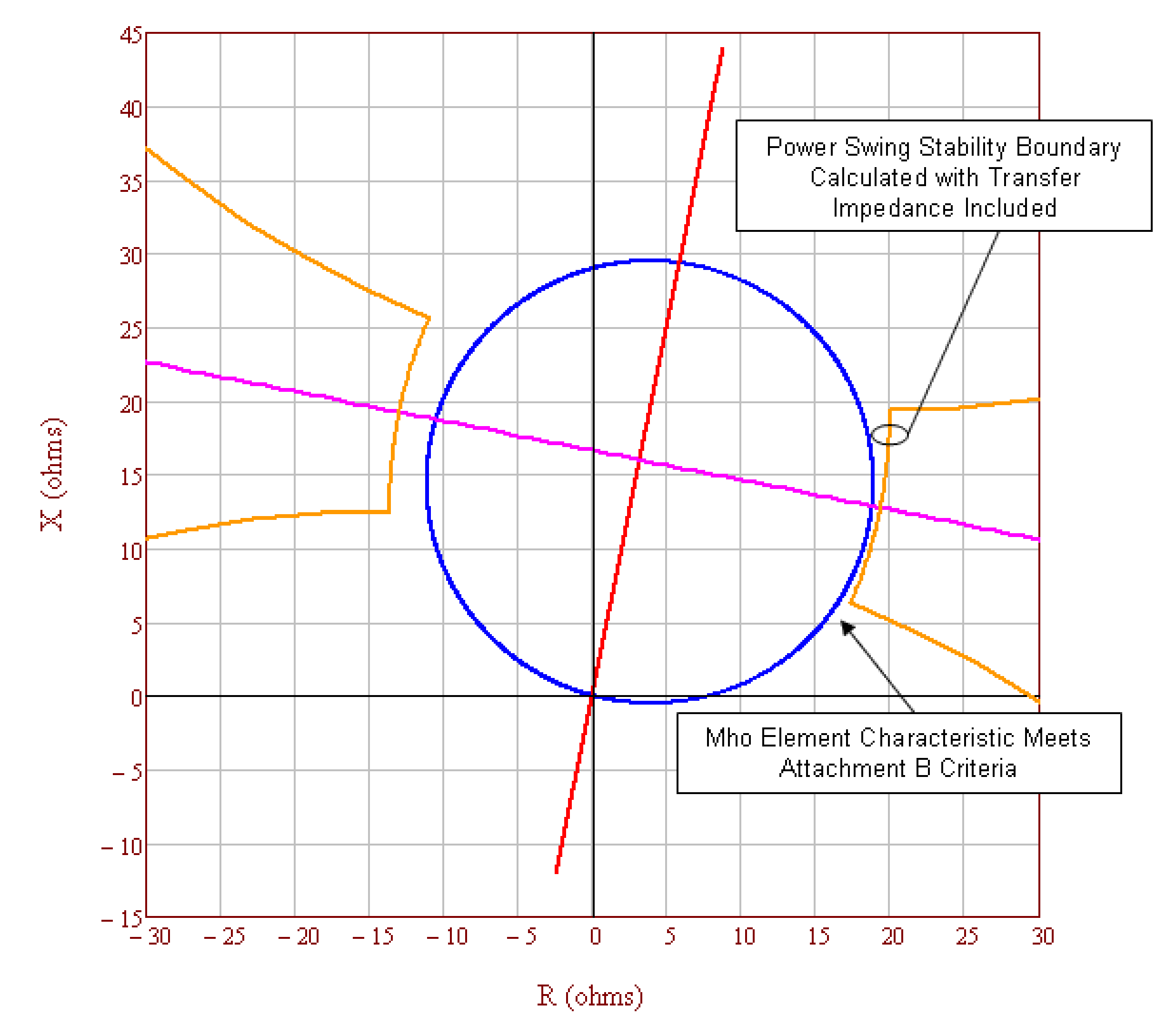


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-~~1~~2 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~2 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-~~1~~2 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

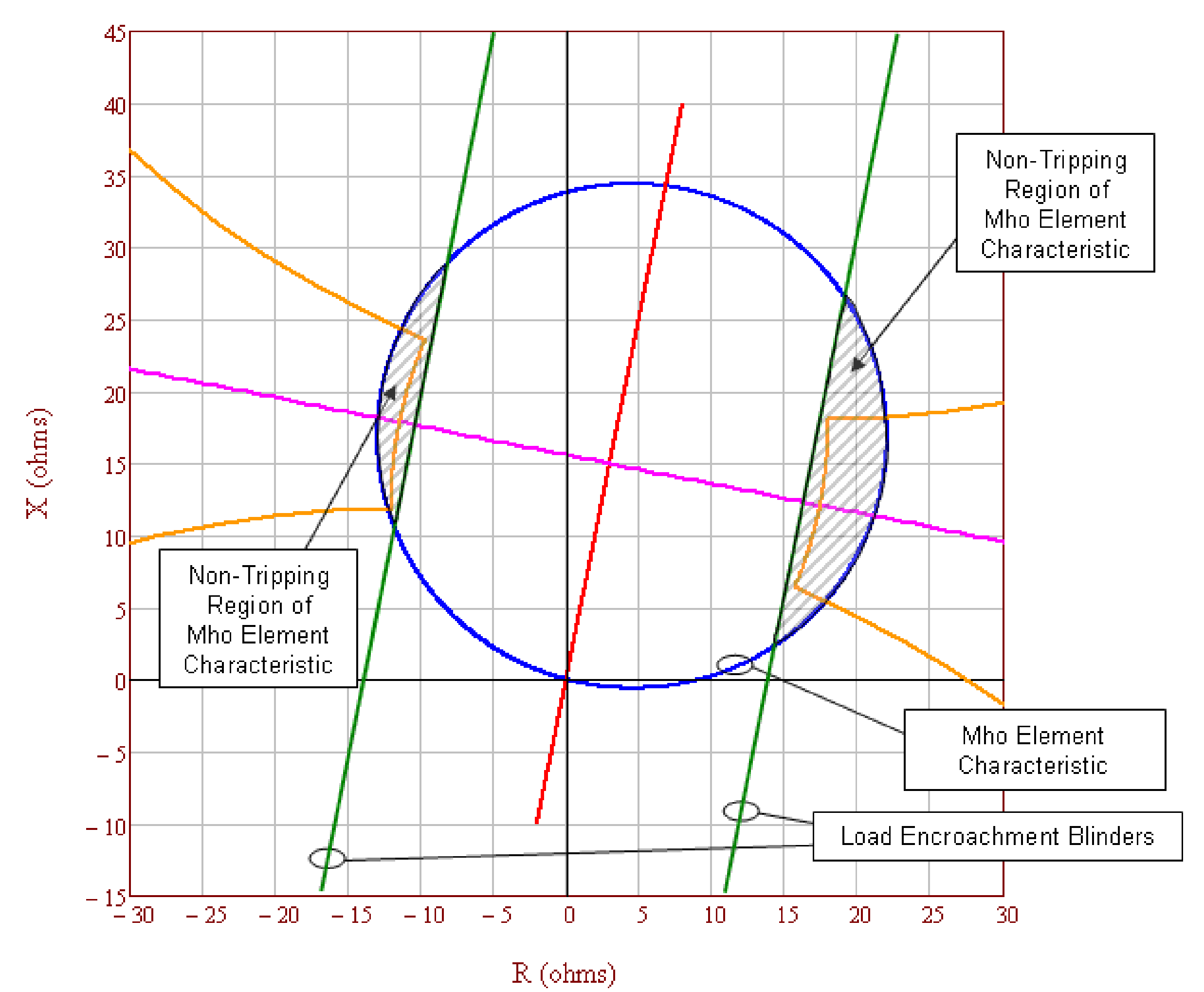


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-~~1~~ 2– Attachment B, Criterion A.

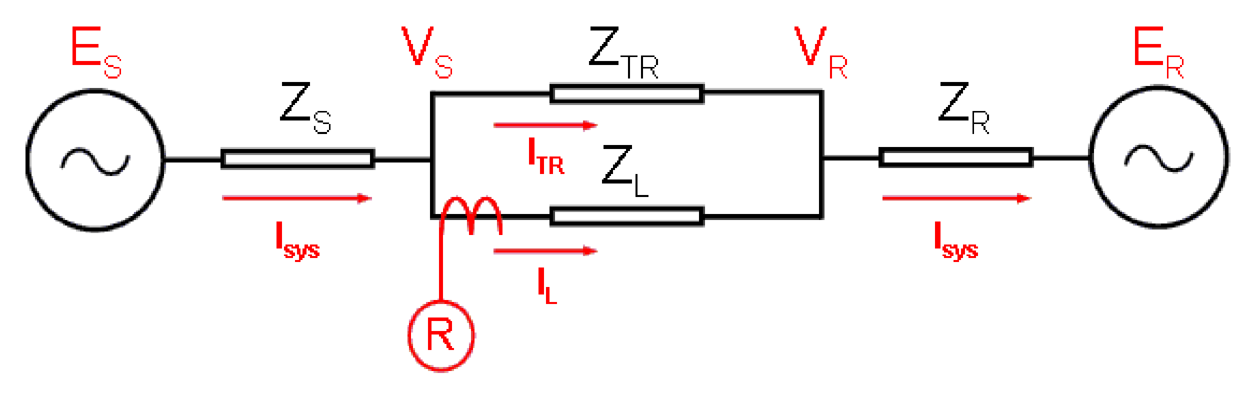


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)

The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.

Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

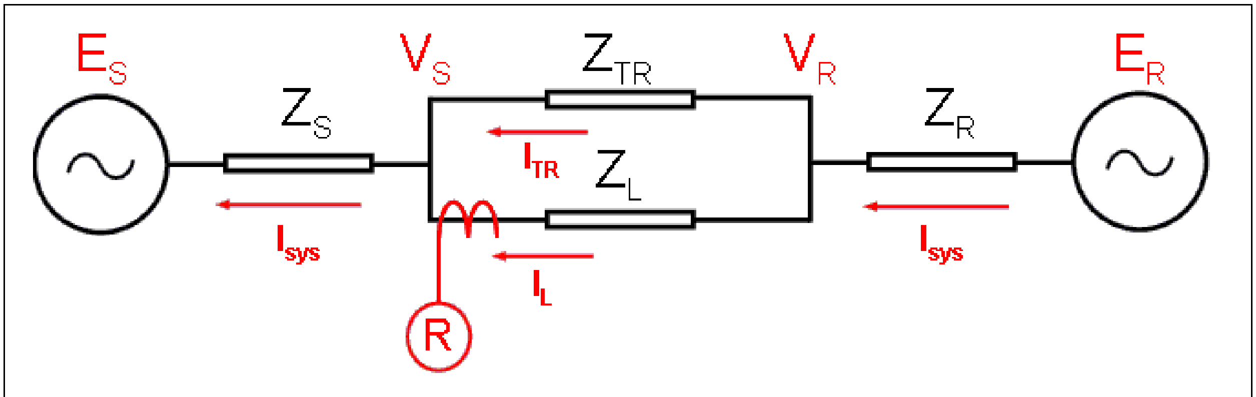


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \dfrac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \dfrac{V_R}{I_L} = Z_L + Z_S + \dfrac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\dfrac{I_{TR}}{I_L} = \dfrac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \dfrac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

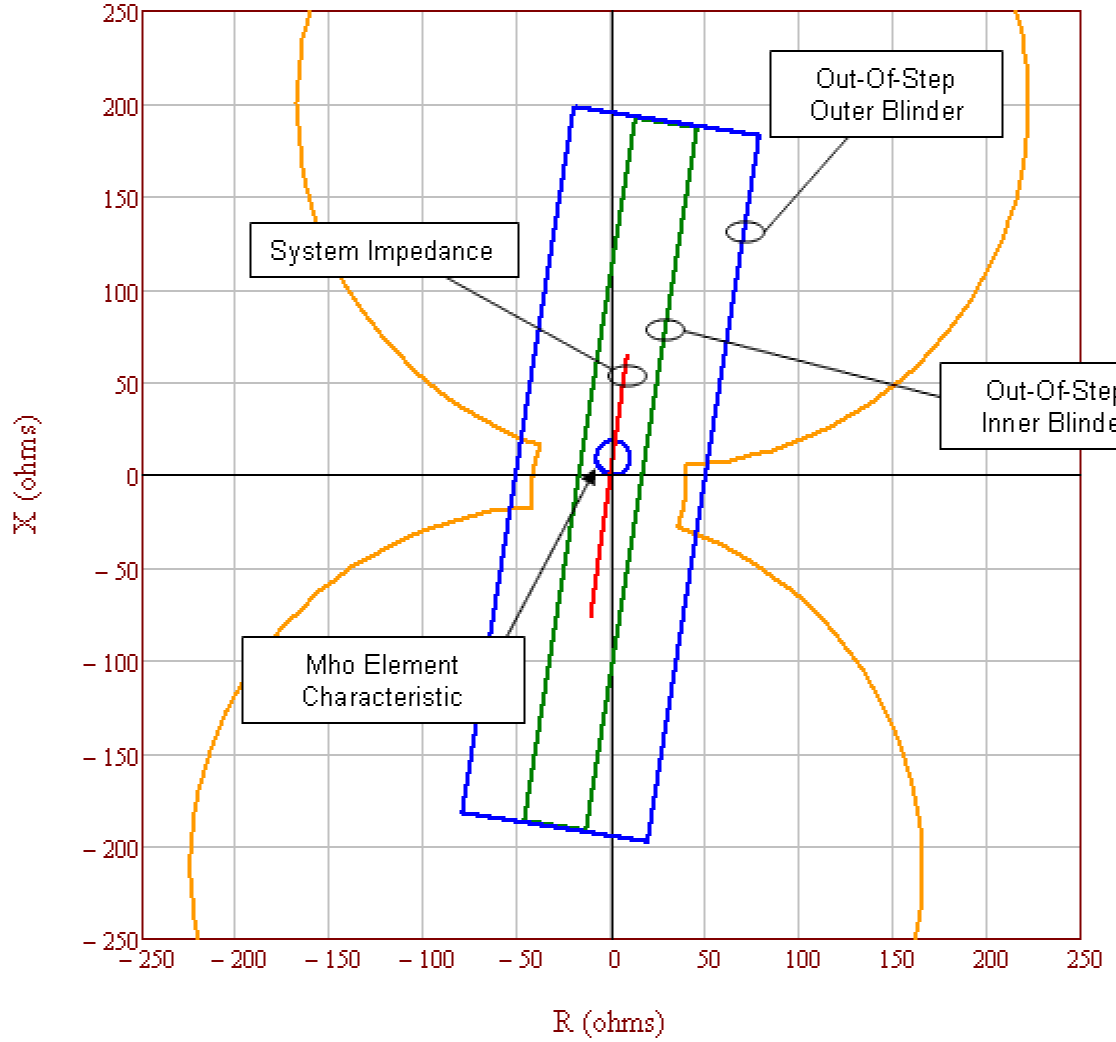


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-~~1~~2 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-~~1~~2 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert\frac{N \times Z_{sys}}{N^2 - 1}\right\rvert$
	$r_b = \left\lvert\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right\rvert$
	$r_b = 69.987\ \Omega$

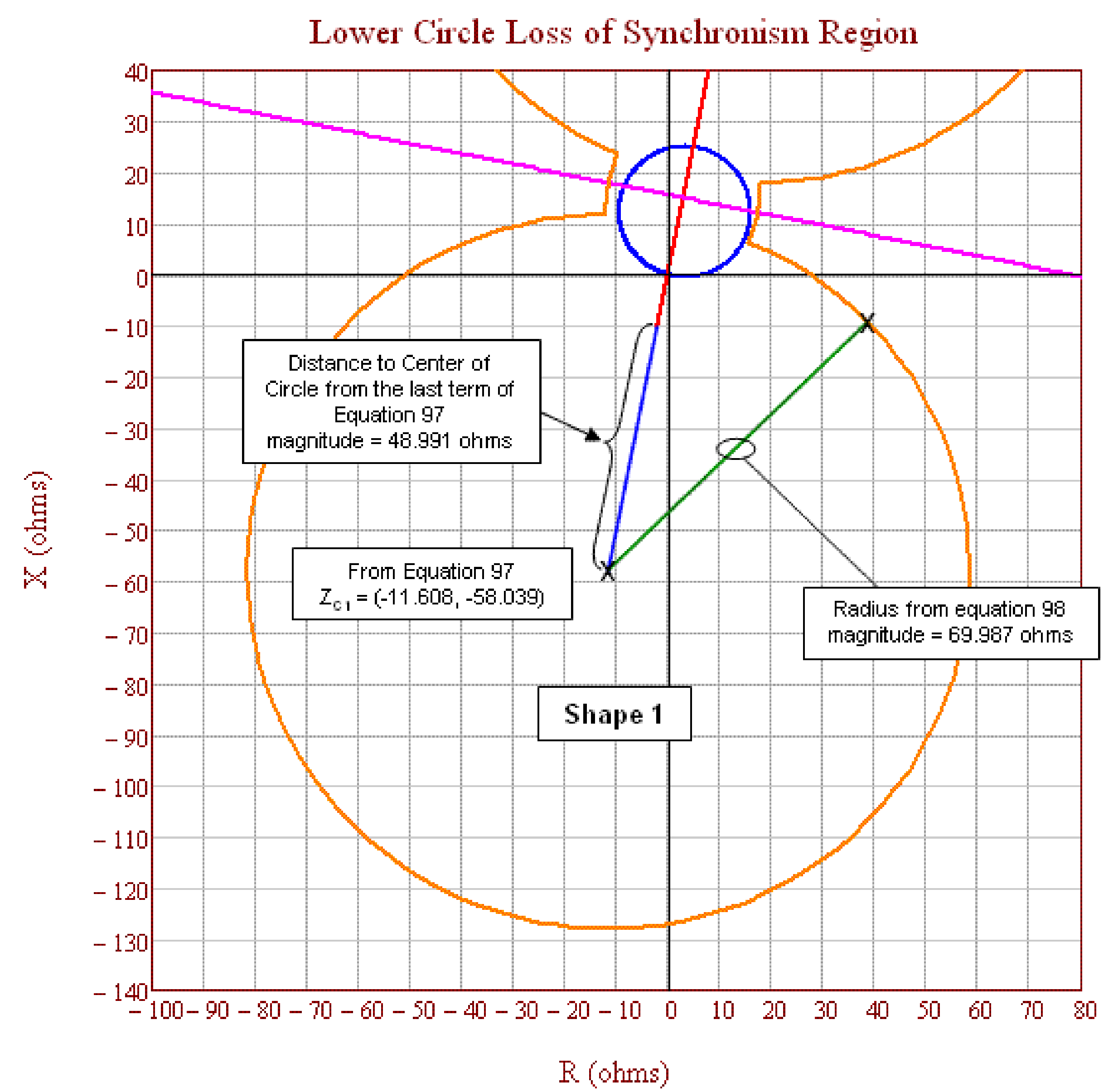


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

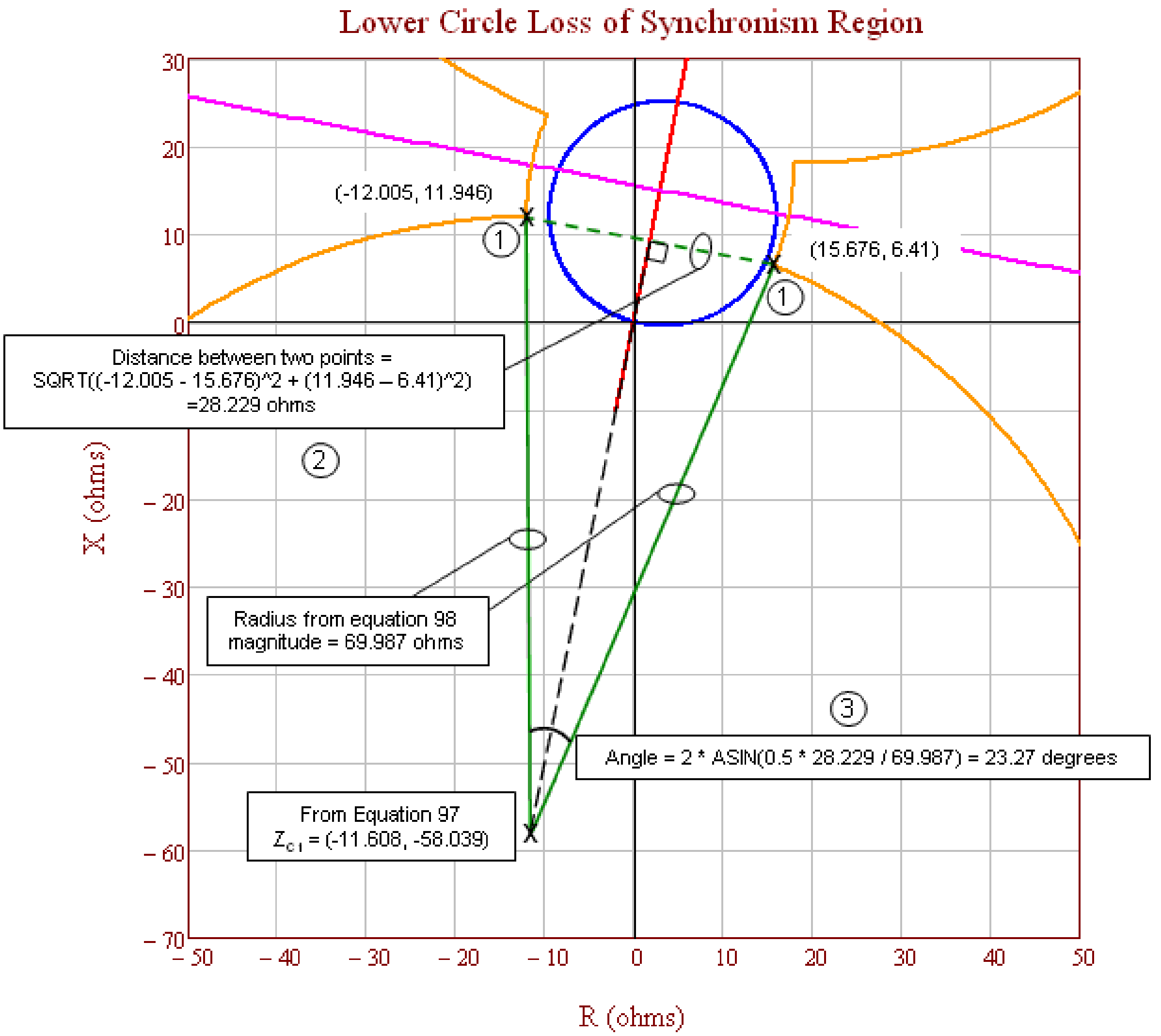


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

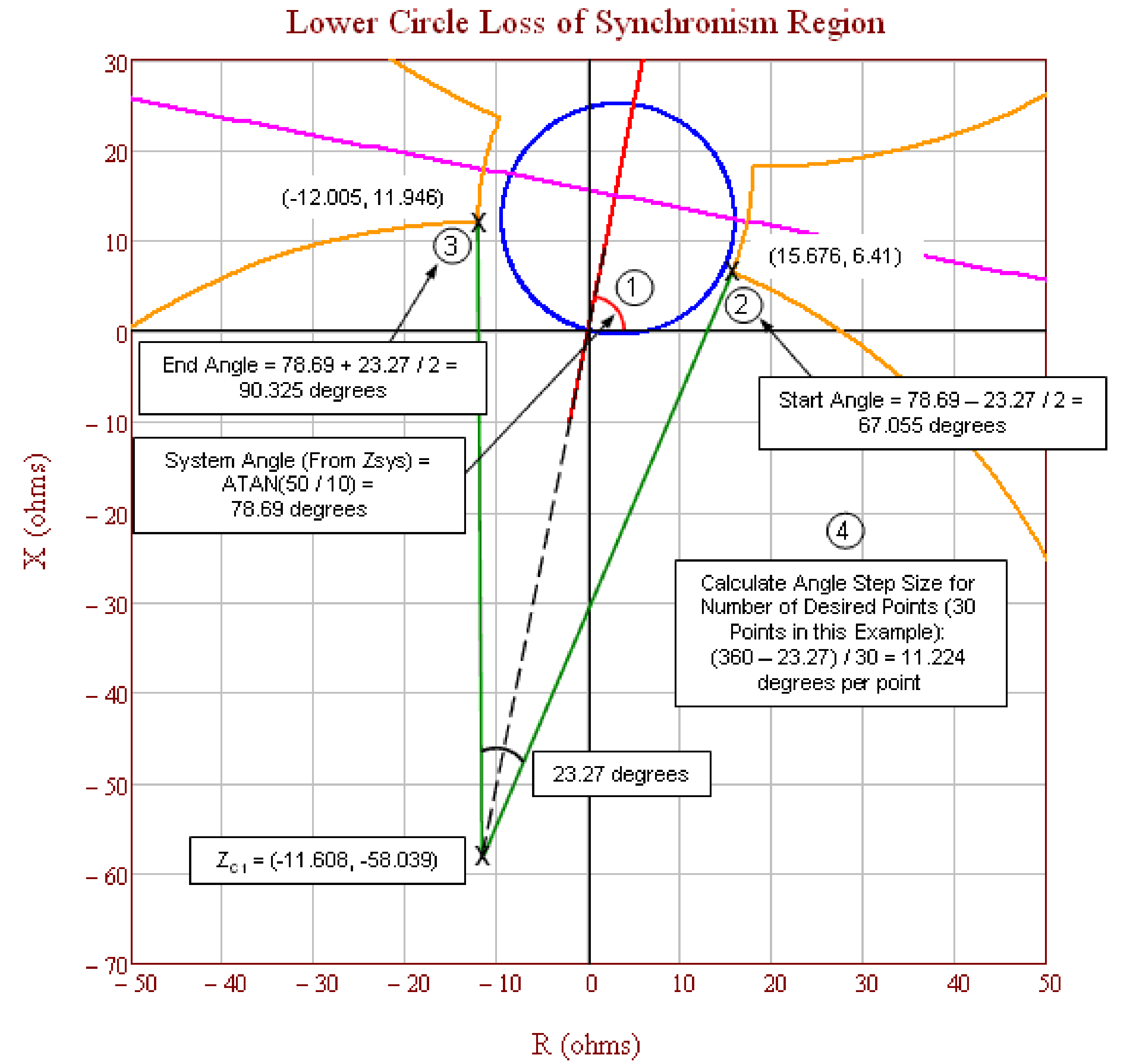


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

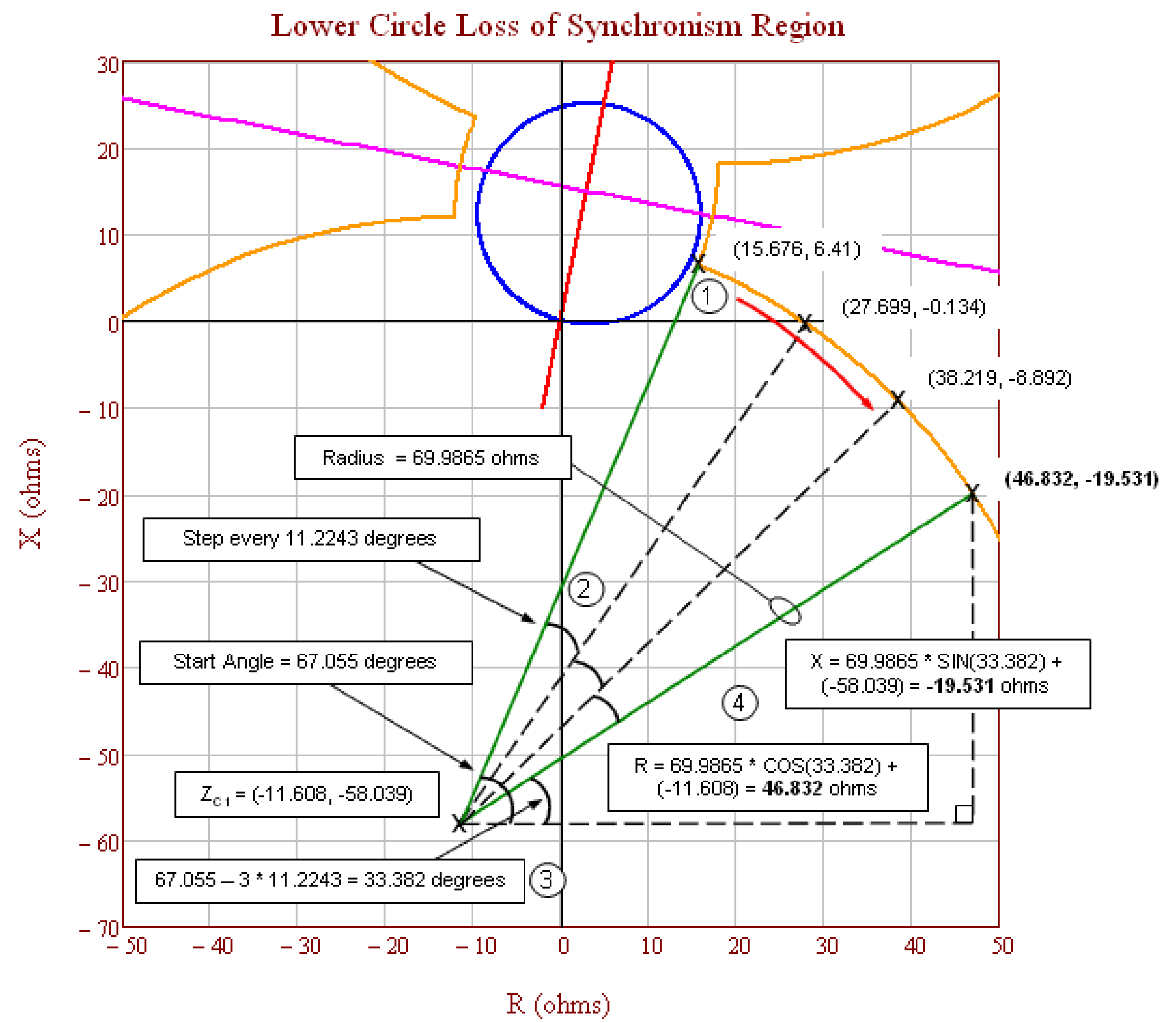


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

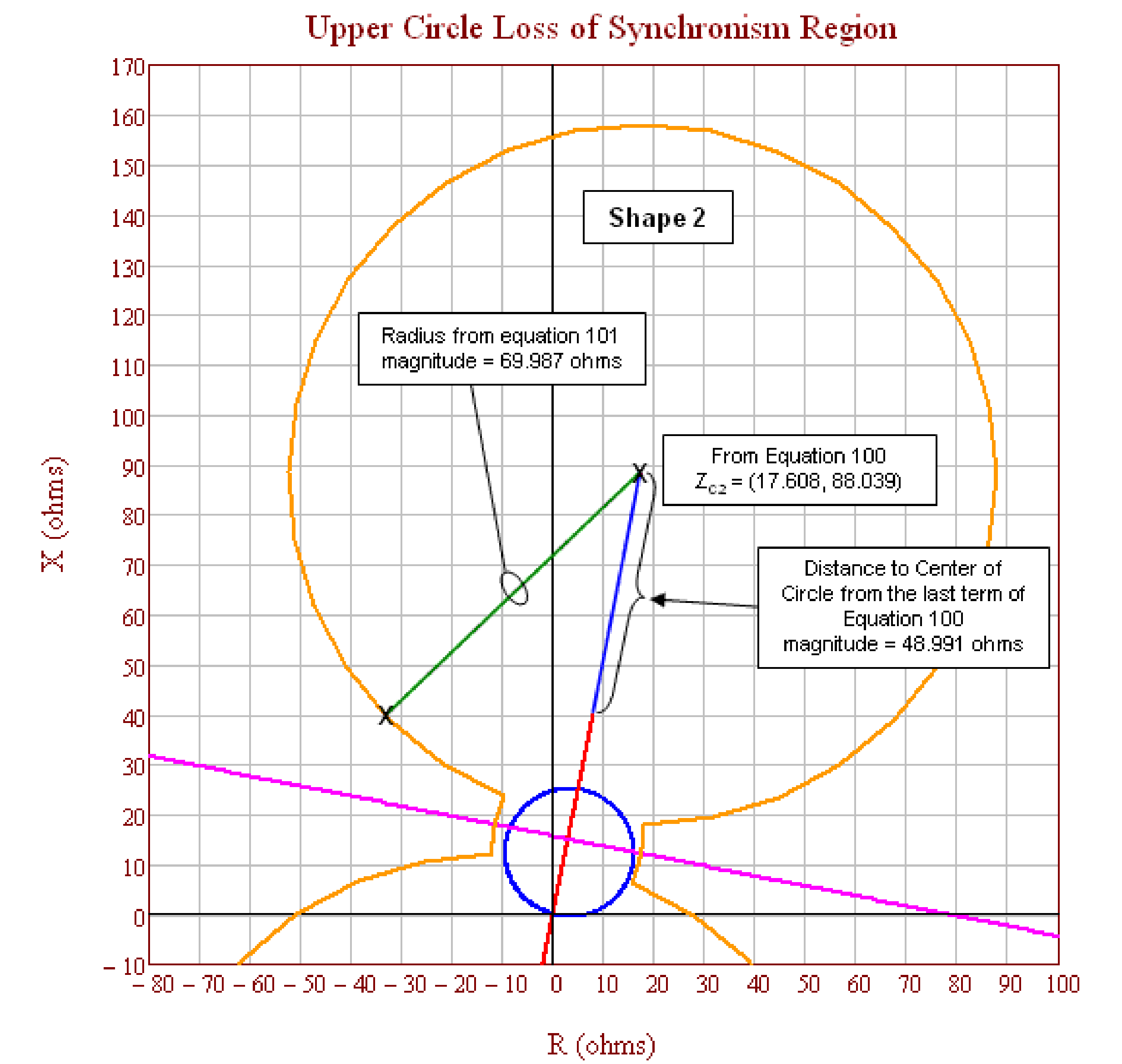


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

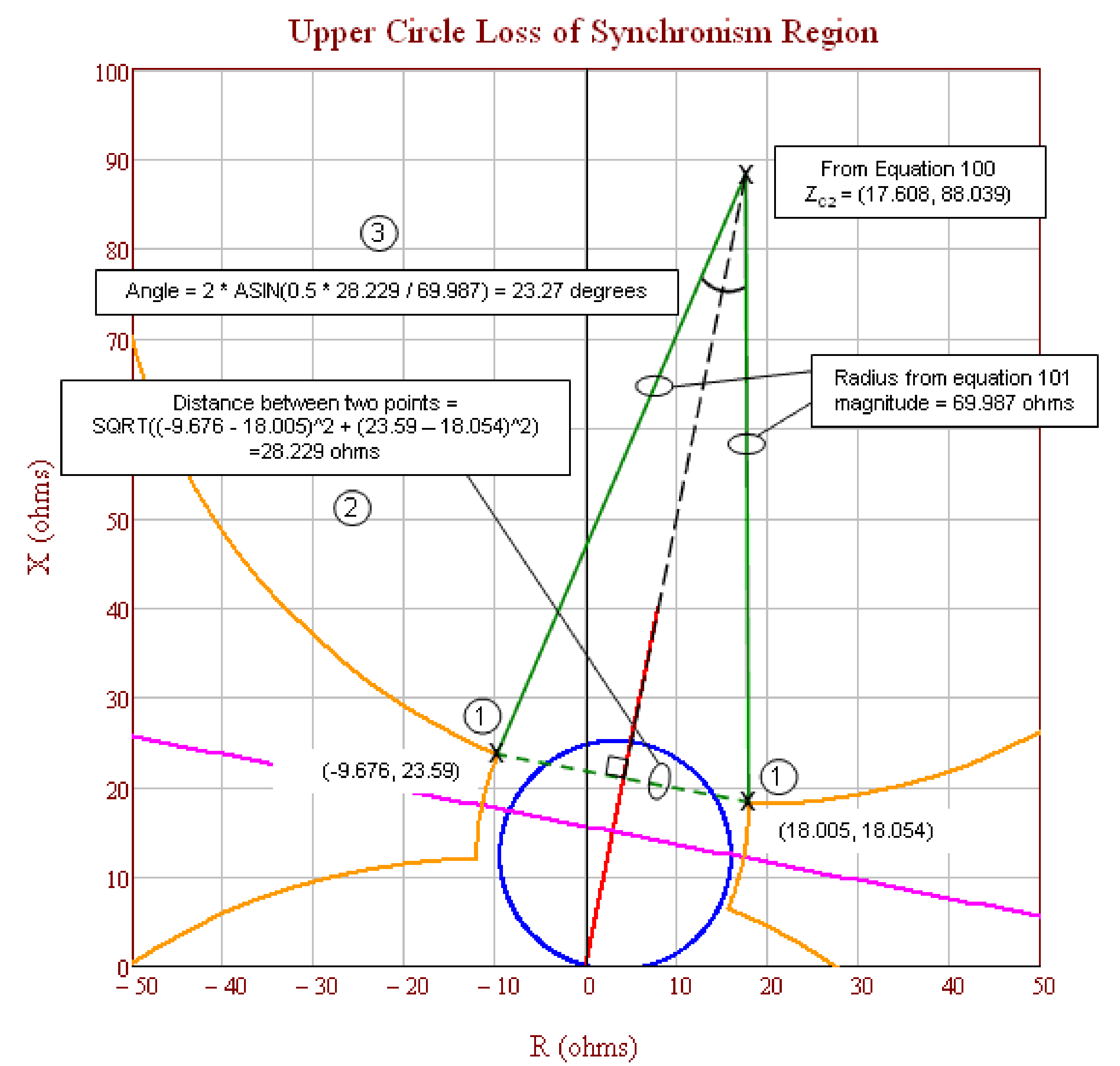


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

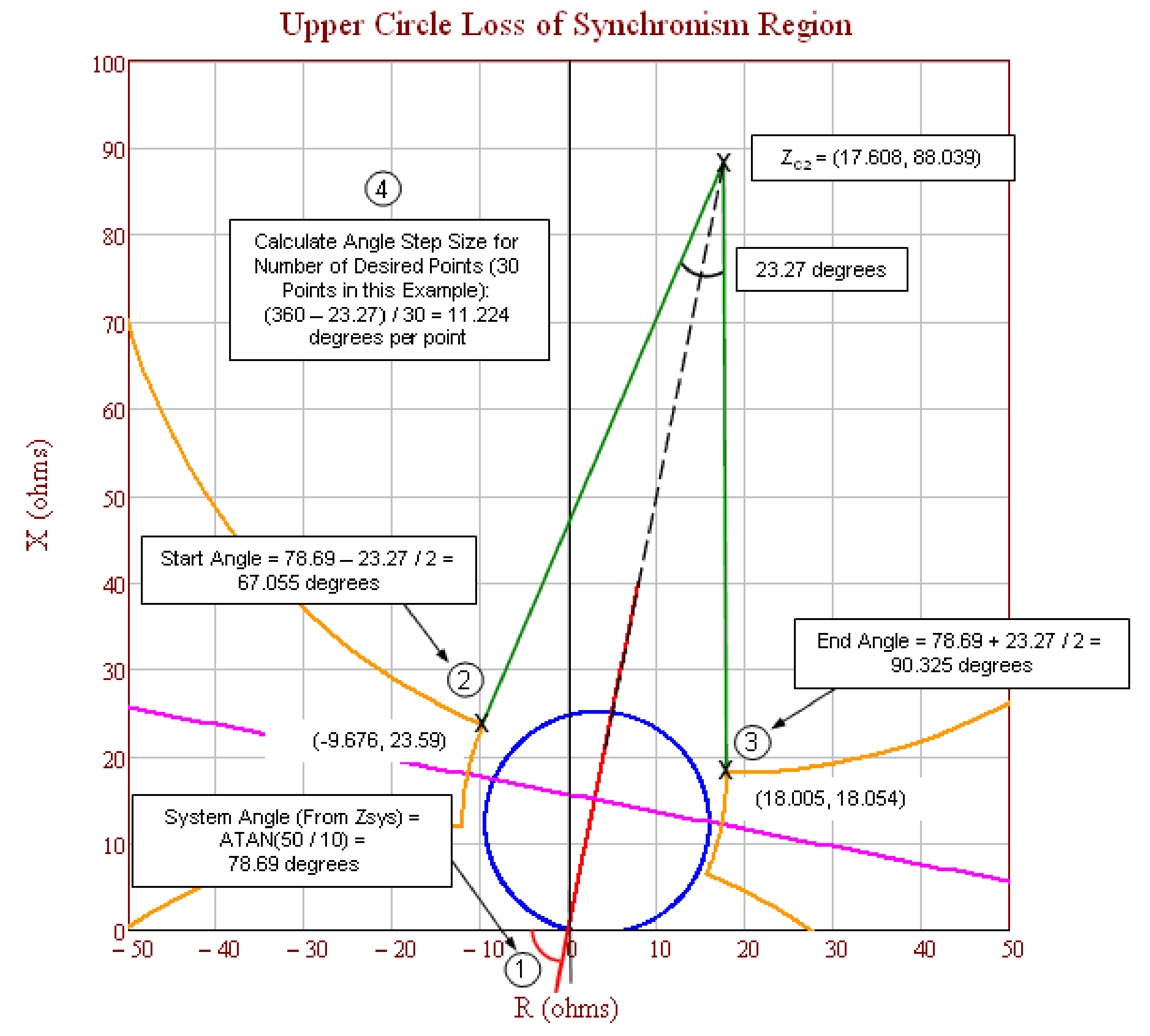


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

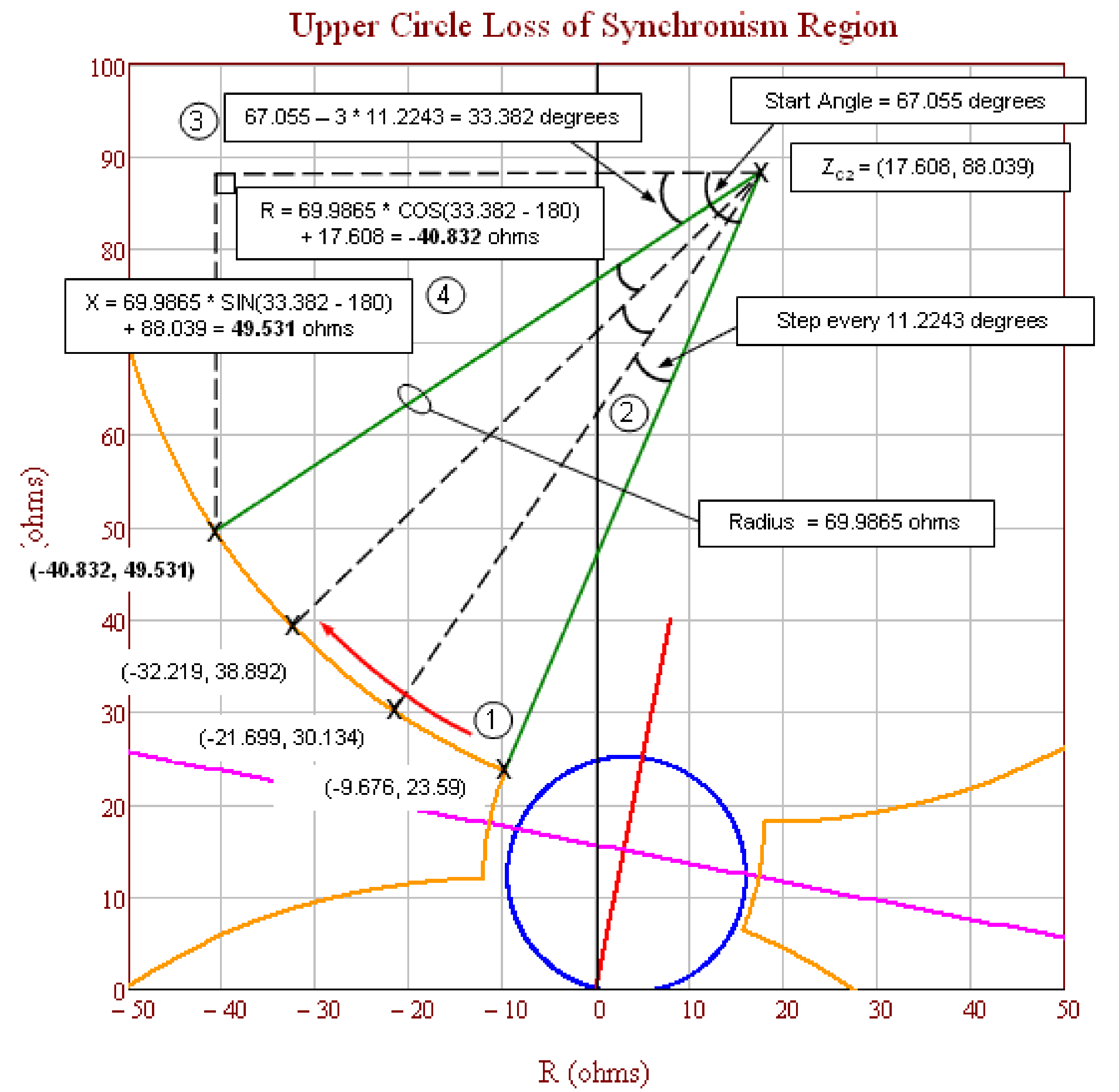


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-~~1~~ 2– Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-~~1~~ 2 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the

maximum power transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

<table>
<tr><th colspan="4">Table 14: Example Calculation (Overcurrent)</th></tr>
<tr><td colspan="4">This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms.

Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-~~1~~2 – Attachment B, Criterion B.</td></tr>
<tr><td>Eq. (102)</td><td colspan="3">$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_S = 139{,}430\angle 120°\ V$</td></tr>
<tr><td colspan="4">Receiving-end generator terminal voltage.</td></tr>
<tr><td>Eq. (103)</td><td colspan="3">$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$</td></tr>
<tr><td></td><td colspan="3">$V_R = 139{,}430\angle 0°\ V$</td></tr>
<tr><td colspan="4">The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.</td></tr>
<tr><td>Given:</td><td>$Z_S = 3 + j26\ \Omega$</td><td>$Z_L = 1.3 + j8.7\ \Omega$</td><td>$Z_R = 0.3 + j7.3\ \Omega$</td></tr>
<tr><td>Eq. (104)</td><td colspan="3">$Z_{sys} = Z_S + Z_L + Z_R$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$</td></tr>
<tr><td></td><td colspan="3">$Z_{sys} = 4.6 + j42\ \Omega$</td></tr>
<tr><td colspan="4">Total system current.</td></tr>
<tr><td>Eq. (105)</td><td colspan="3">$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$</td></tr>
<tr><td></td><td colspan="3">$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$</td></tr>
<tr><td></td><td colspan="3">$I_{sys} = 5{,}715.82\angle 66.25°\ A$</td></tr>
</table>

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

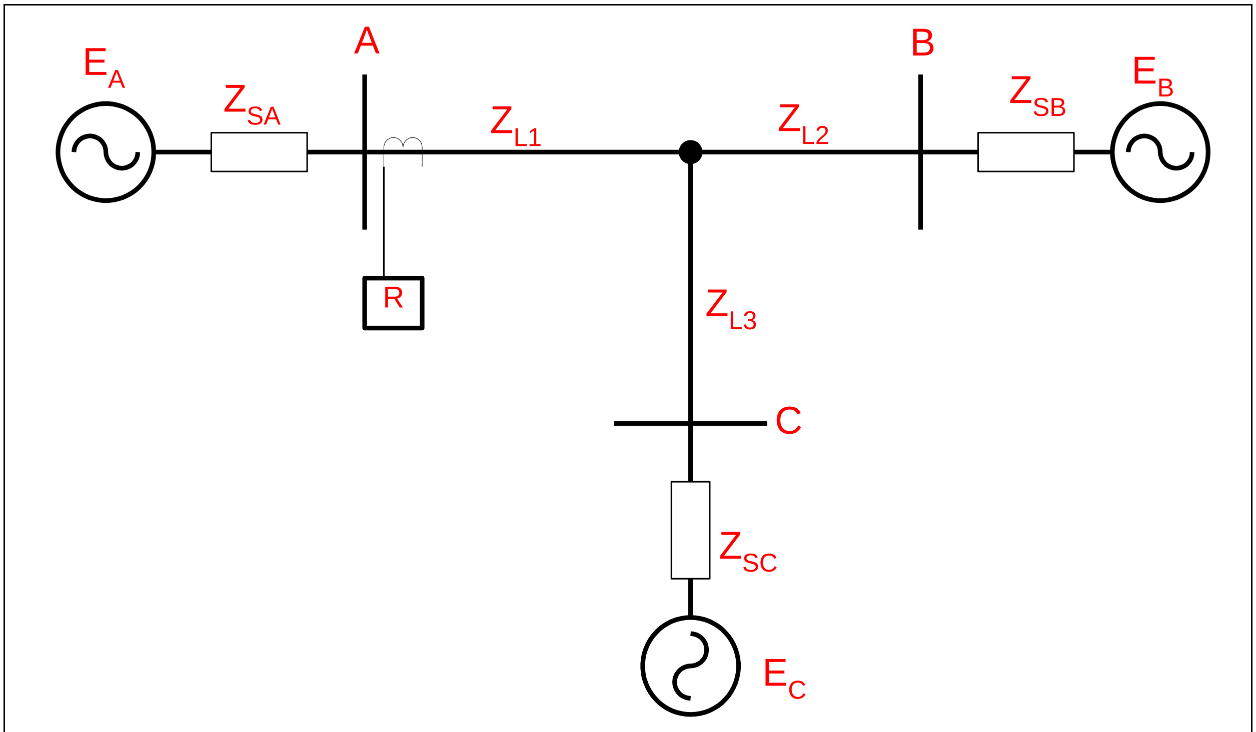


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

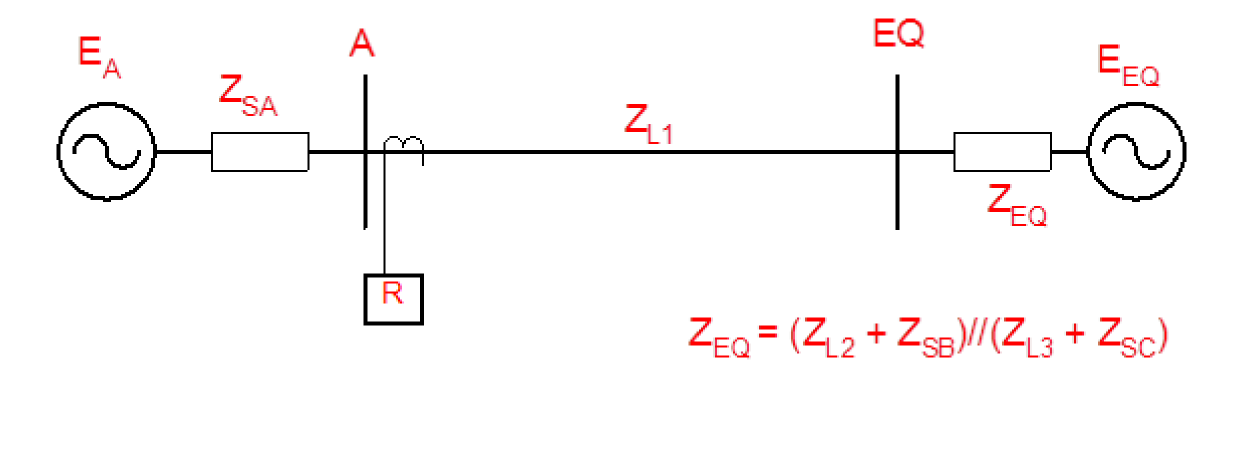


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-~~1~~2 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

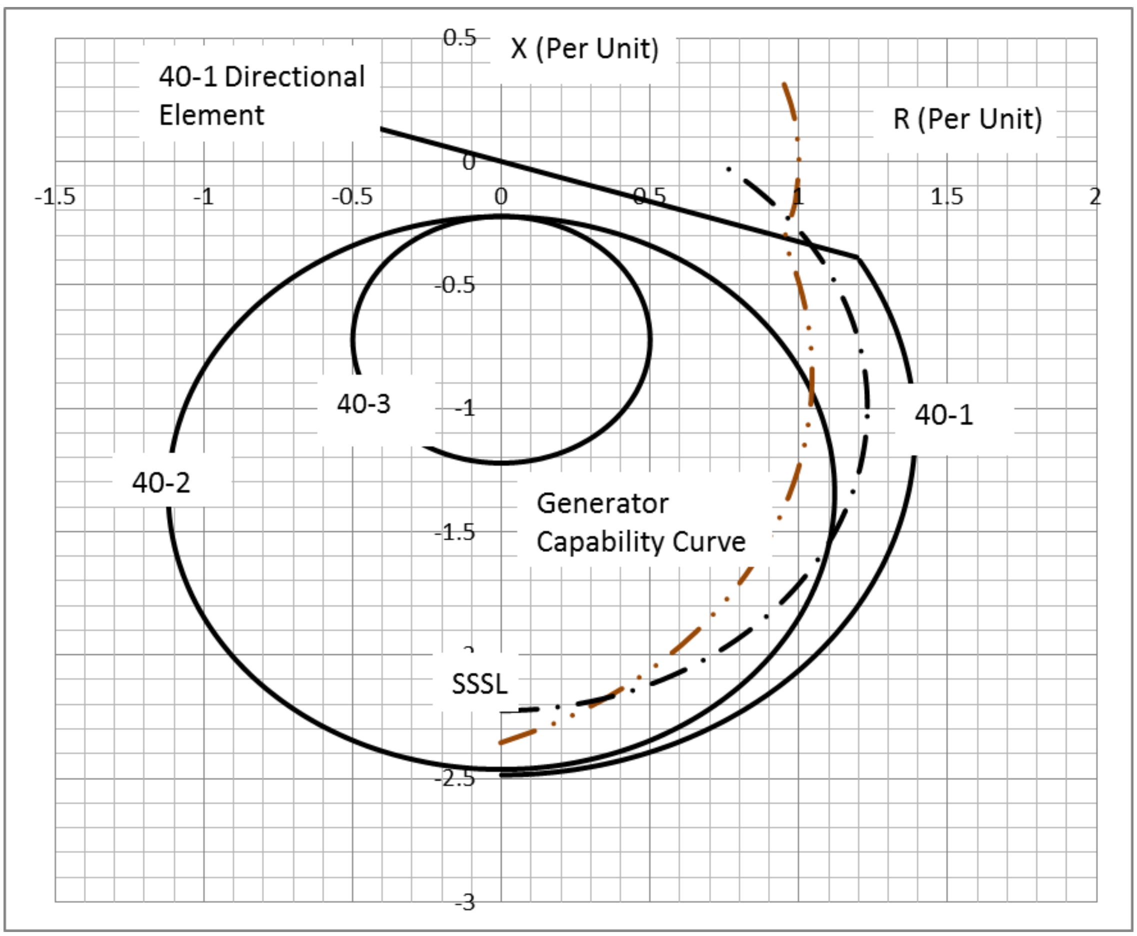


Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-~~1~~2, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-~~1~~ 2 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

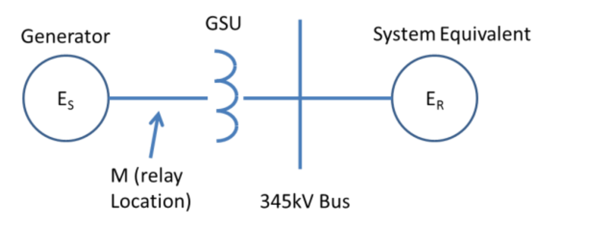	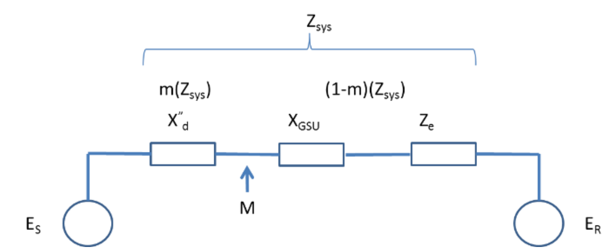
Figure 17: Simple one-line diagram of the system to be evaluated.	**Figure 18:** Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset $= 0.294$ per unit
	Diameter $= 0.294$ per unit
40-2	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 2.24$ per unit
40-3	Negative Offset Impedance
	Offset $= 0.22$ per unit
	Diameter $= 1.00$ per unit
21-1	Diameter $= 0.643$ per unit
	MTA $= 85°$

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle120°) + (0.6163)(1\angle0°)}{1\angle120° - 1\angle0°}\right) \times (0.6239\angle90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194\angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.						
	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-~~1~~ 2– Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

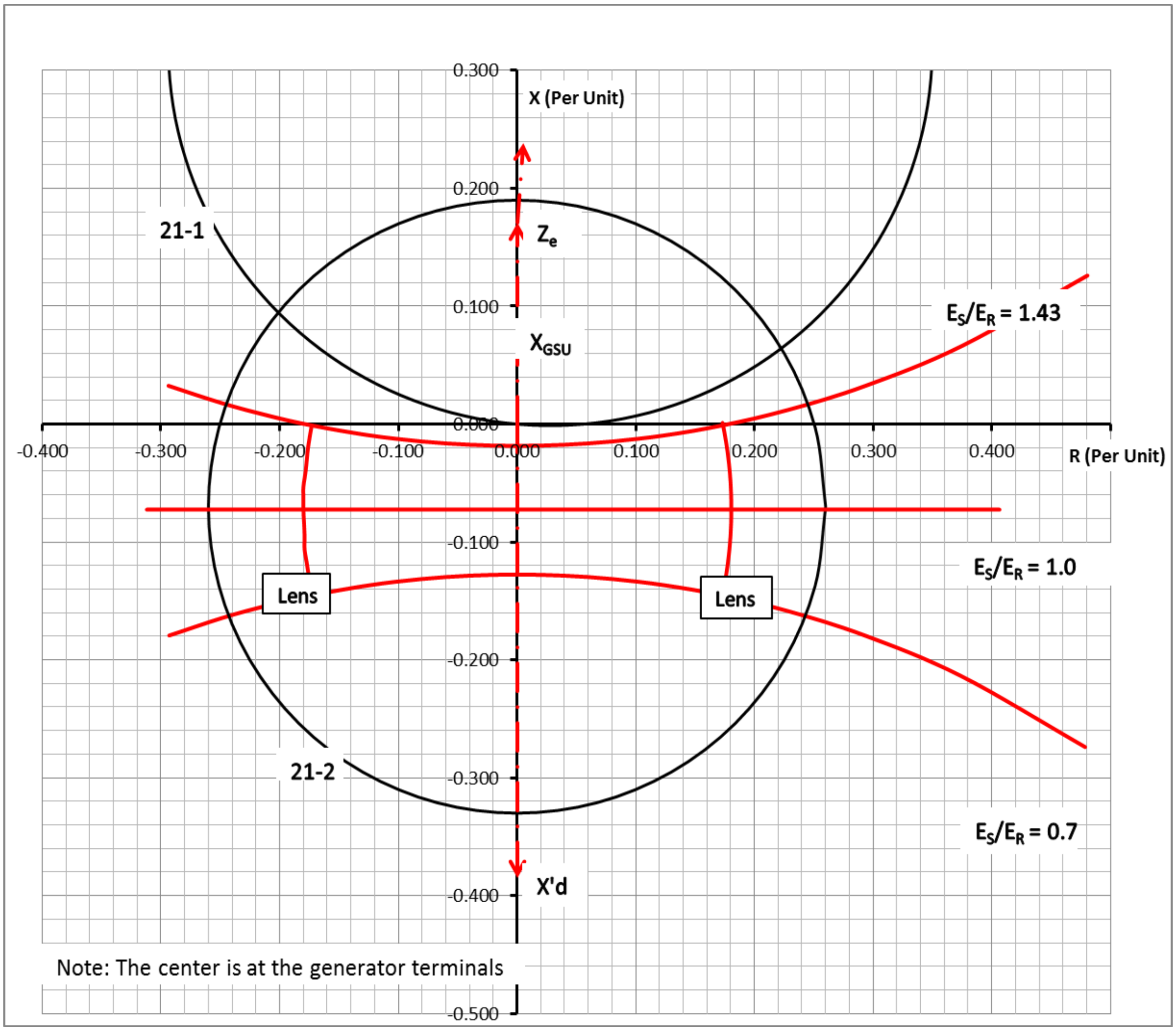

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

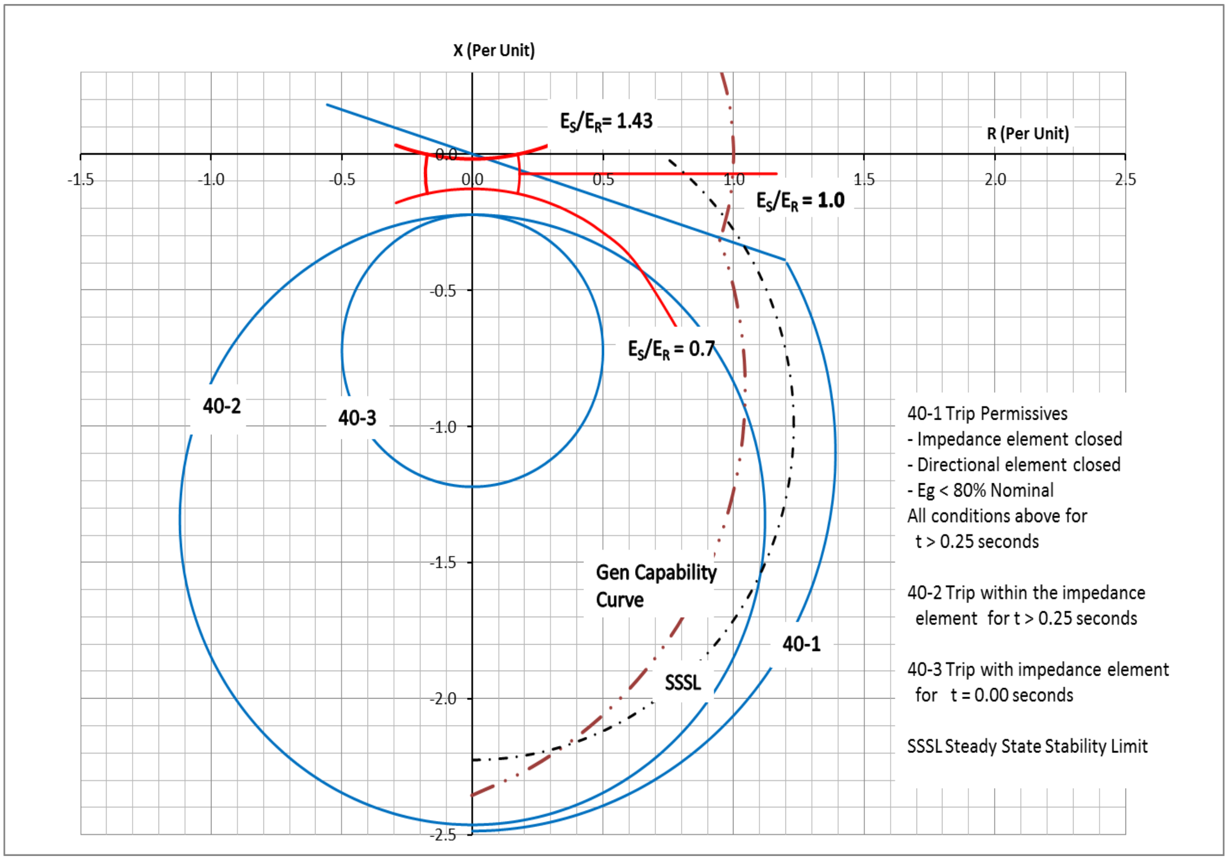

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-~~1~~2 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-~~1~~2 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150^\circ}{0.6239\angle 90^\circ} pu$$

$$I_{sys} = 2.91\ \angle 60^\circ\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-~~1~~ 2 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-~~1~~2 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

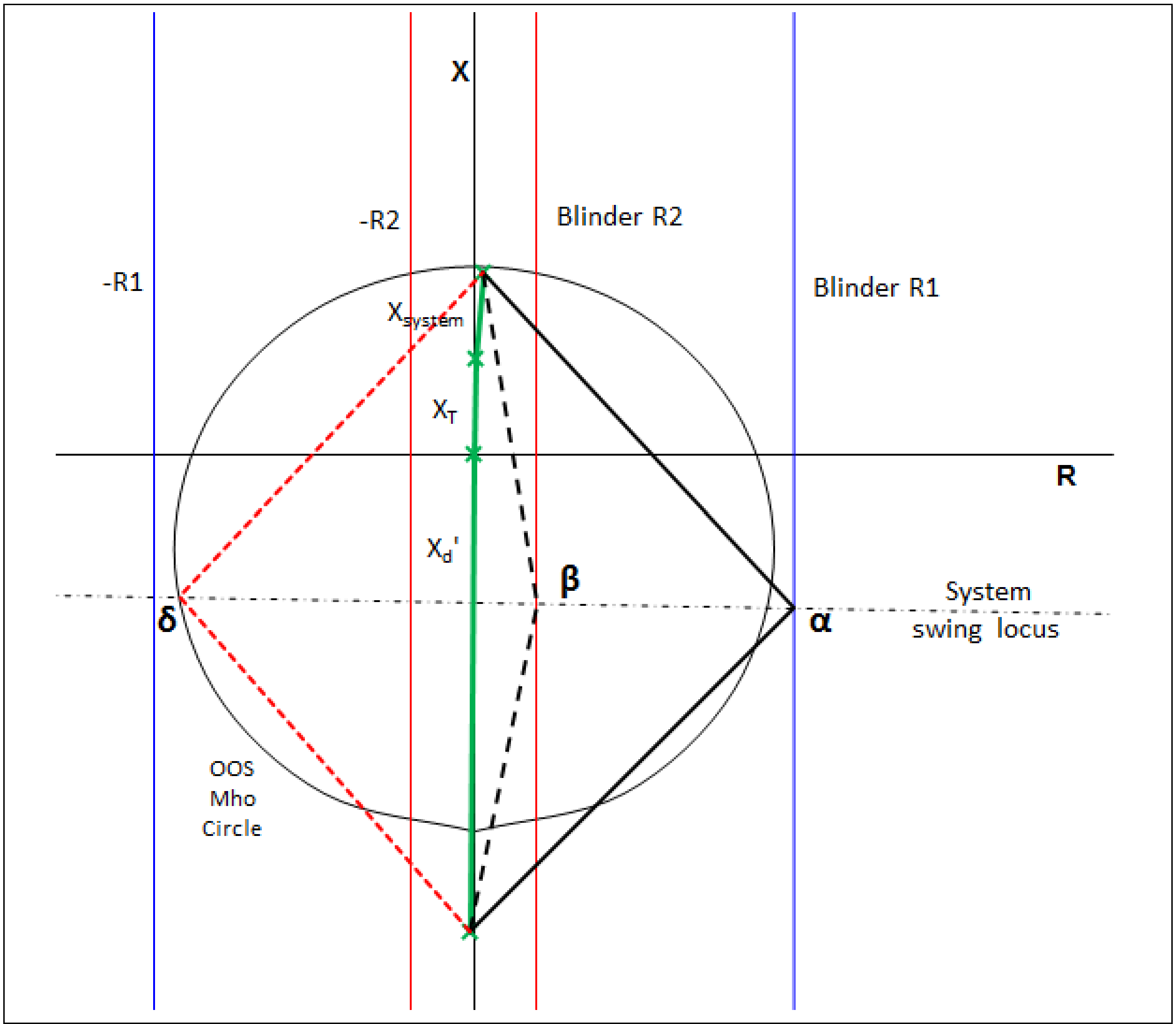

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

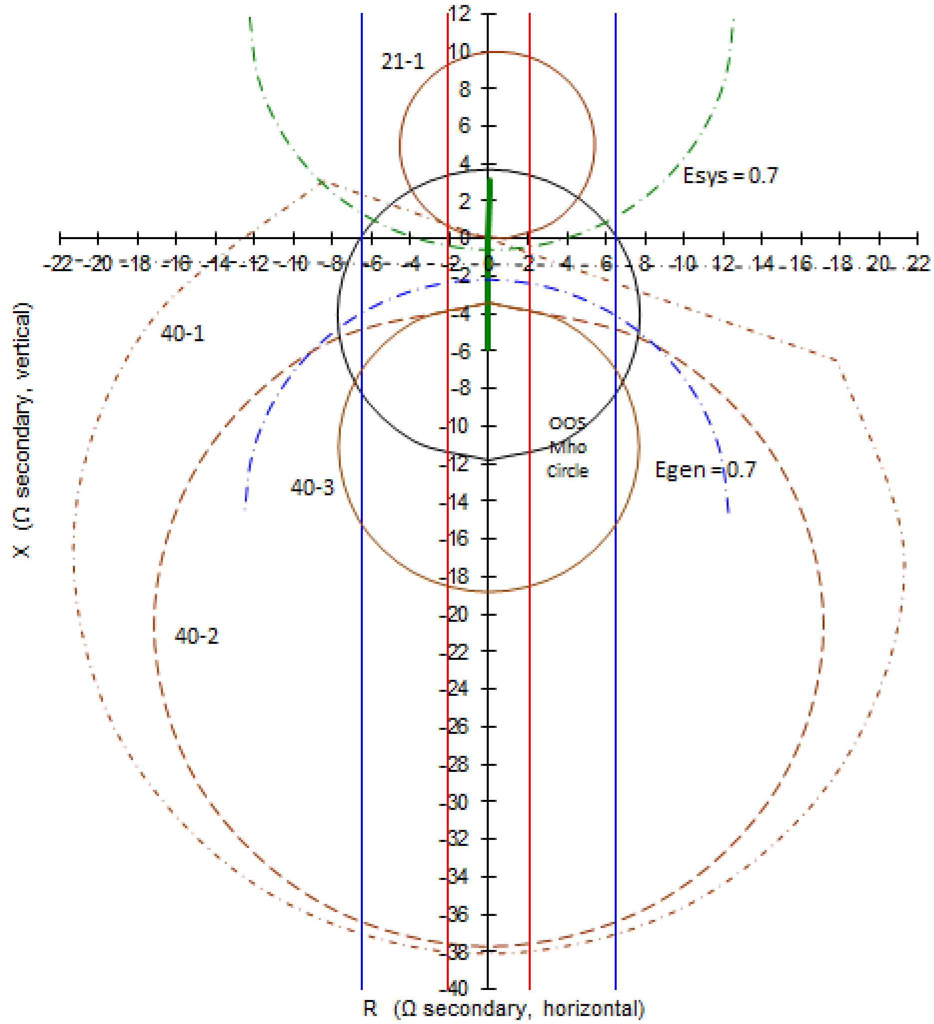

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-~~1~~2 – Attachment B criteria or can be excluded under the PRC-026-~~1~~2 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-~~1~~2 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-~~1~~2 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-~~1~~2 – Attachment B criteria.

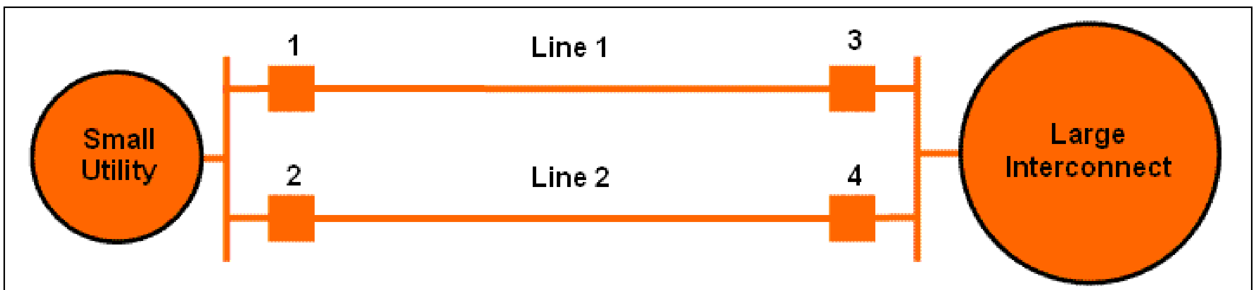

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

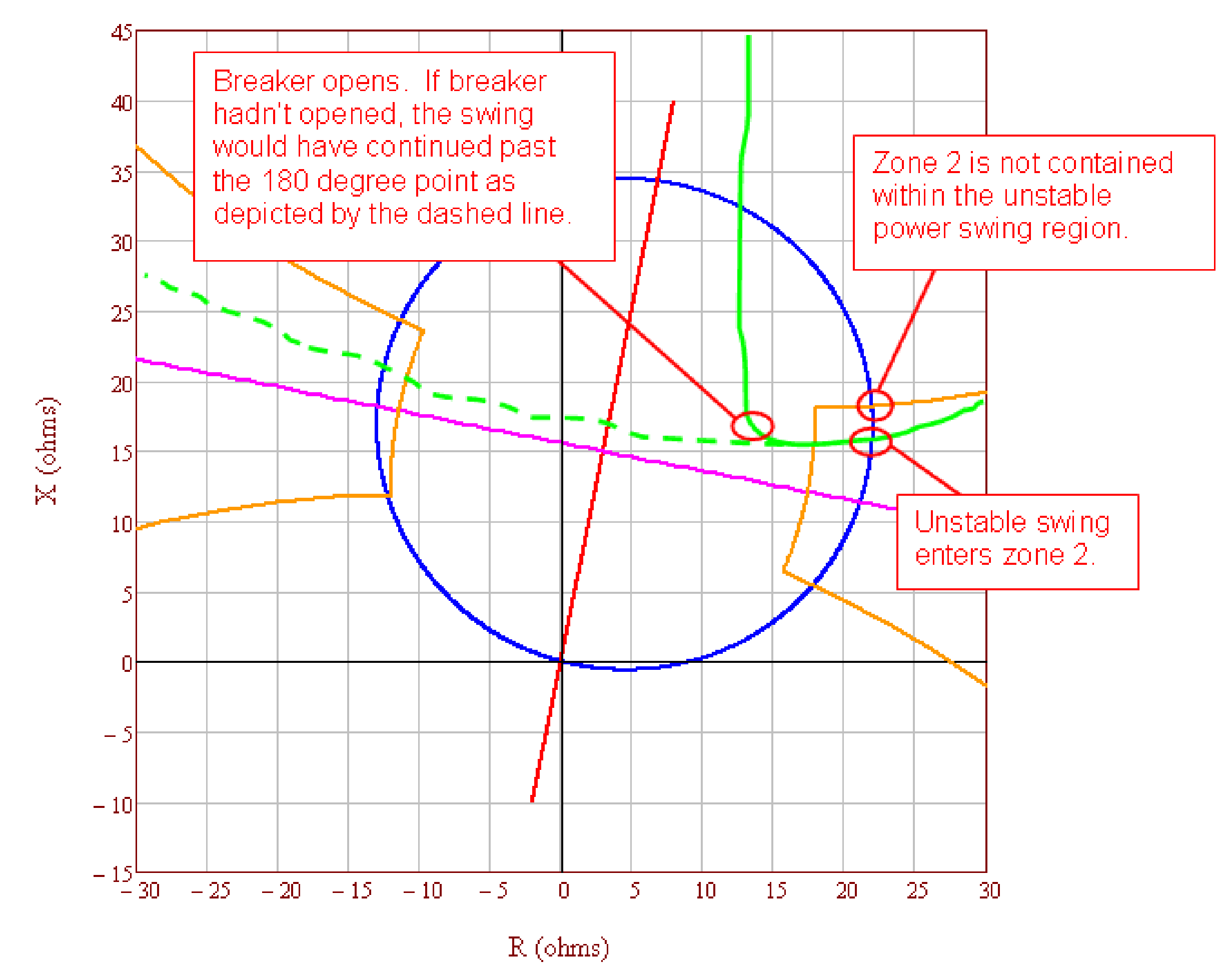

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-~~1~~2 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

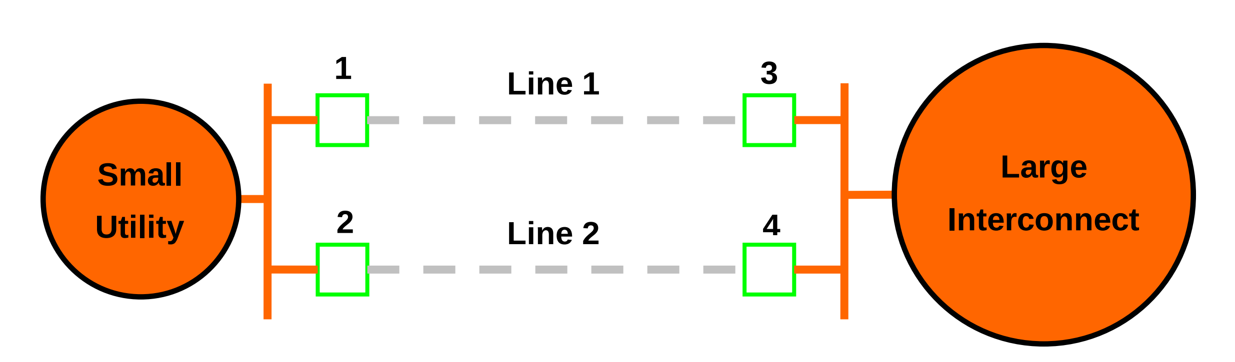

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

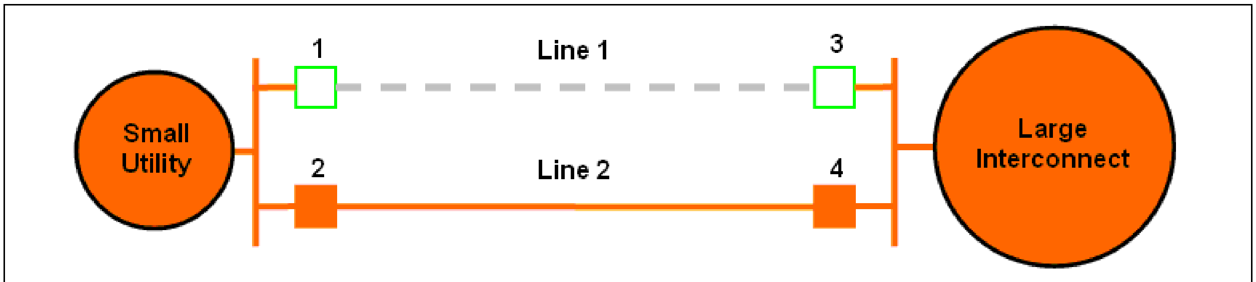

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

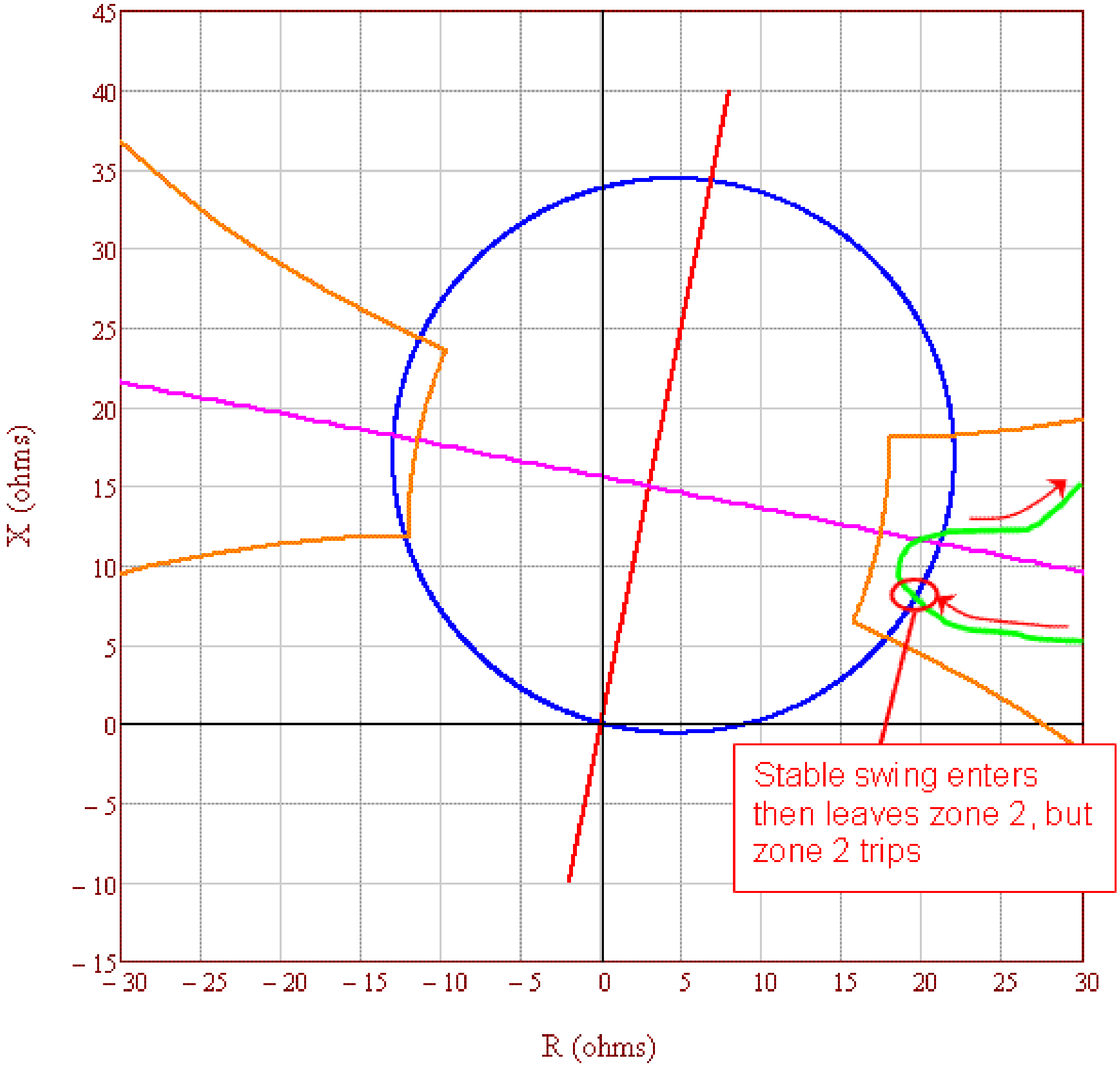

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the ~~PRC-026-1~~PRC-026-2 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

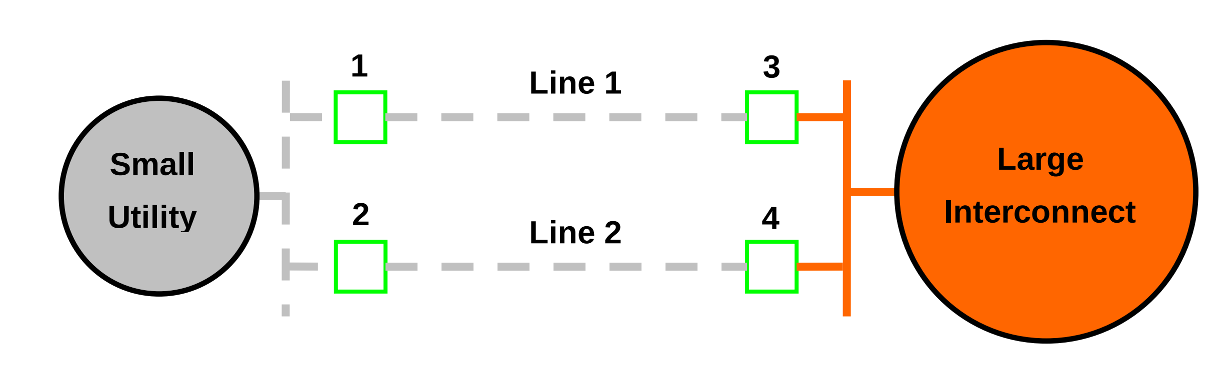

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-~~1~~2 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-~~1~~2 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

analysis or Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-~~1~~2 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-~~1~~2 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-~~1~~2 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-3
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, R6, and R7 and Measures M1 through M3, M5, M6, and M7 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan,

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit	when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Area.		(IROL) exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing	The Reliability Coordinator did not notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan	Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit	Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability	when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			when the when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	(SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	TBD	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

Note: The Guidelines and Technical Basis section has not been revised as part of Project 2015-09. A separate technical rationale document has been created to cover Project 2015-09 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with additional ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-~~2~~3
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

    4.1. Reliability Coordinator.

5. **Proposed Effective Date:**

    See Implementation Plan.

6. **Background**

    See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Reliability Operating ~~Reliability~~ Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include, but is not limited to, dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify, in accordance with its SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify, in accordance with SOL methodology, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it used its SOL methodology for determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Operating Plans, contingency sets, SOLs, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, ~~and~~ R6, and R7 and Measures M1 through M3, M5, ~~and~~ M6, and M7 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Reliability Operating ~~Reliability~~ Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Authorities.
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time	High	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period,	For any sample 24-hour period within the 30-day retention	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations		period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL)	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection	Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			exceedance within its Wide Area.		Reliability Operating Limit (IROL) exceedance within its Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify, in accordance with its SOL methodology one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities	The Reliability Coordinator did not notify, in accordance with its SOL methodology two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing	The Reliability Coordinator did not notify, in accordance with its SOL methodology three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission	The Reliability Coordinator did not ~~notify ,~~notify, in accordance with its SOL methodology four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as	Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three	impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			indicated in its Operating Plan when the when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) exceedance or an Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.	
R7	Same-Day Operations, Real-time Operations	Medium				The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-008-2. Docket No. RM15-16-000. Order No. 817	
3	TBD	Adopted by NERC Board of Trustees	Revisions under Project 2015-09

Note: The Guidelines and Technical Basis section has not been revised as part of Project 2019-02. A separate technical rationale document has been created to cover Project 2019-02 revisions. Future edits to this section will be conducted through the Technical Rationale for Reliability Standards Project and the Standards Drafting Process.

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~

~~Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.~~

~~Rationale for R2 and R3:~~

~~Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.~~

~~Rationale for R5 and R6:~~

~~In Requirements R5 and R6 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

None

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Generator Operator
     - **4.1.4.** Distribution Provider
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two

hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	TBD	Adopted by the Board of Trustees	Revised

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
45-day formal comment period with initial ballot	06/19/20 – 08/26/20

Anticipated Actions	Date
10-day final ballot	April 2021
NERC Board adoption	May 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Proposed Modified Term

System Operating Limit:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

None

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-001-~~5~~6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

10.3. Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator;

10.4. Obtain and utilize status, voltages, and flow data for Facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator;

10.5. Obtain and utilize the status of Remedial Action Schemes outside its Transmission Operator Area identified as necessary by the Transmission Operator; and

10.6. Obtain and utilize status, voltages, and flow data for non-BES facilities outside its Transmission Operator Area identified as necessary by the Transmission Operator.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the

excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence. Other evidence could include but is not limited to: Reliability Coordinator's SOL methodology, system logs/records showing successfully mitigated SOL exceedances in conjunction with Operating Plans (e.g. mutually agreed operating protocols between TOPs and their Reliability Coordinator, Operating Procedures, Operating Processes, operating policies, generator redispatch logs, equipment settings for automatically switched equipment and reactive power/voltage control devices, switching schedules, etc.).

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded in accordance with its Reliability Coordinator's SOL methodology. Such evidence could include but is not limited to dated operator logs, electronic communications, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Reserved.

M19. Reserved.

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M20. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from

in order to perform its Real-time monitoring and Real-time Assessments as specified in the requirement.

R21. Each Transmission Operator shall test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Transmission Operator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M21. Each Transmission Operator shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R20 for the redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R21. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R22. Reserved.

M22. Reserved.

R23. Each Balancing Authority shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and analysis functions. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system specifications, system diagrams, or other documentation that lists its data exchange capabilities, including redundant and diversely routed data exchange infrastructure within the Balancing Authority's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

R24. Each Balancing Authority shall test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Balancing Authority shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~R25.~~ M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated

action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations, Operations Planning]*

M25. Each Transmission Operator shall have, and provide upon request, evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. Evidence could include, but is not limited to: Reliability Coordinator's SOL methodology, Operating Plans, contingency sets, alarming and study reporting thresholds, operator logs, voice recordings or other equivalent evidence.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 ~~for three calendar years~~~~rolling~~for rolling 12 months.
- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R18, and Measure M15 through M18 for the current calendar year and one

previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

- Each Transmission Operator shall keep data or evidence for Requirement R20 and Measure M20 for the current calendar year and one previous calendar year.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep data or evidence for Requirement R23 and Measure M23 for the current calendar year and one previous calendar year.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall retain evidence that it used the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis as specified in Requirement R25 and Measurement M25 for a rolling 12 months.

~~1.4.~~1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2.	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4.	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				comply with an Operating Instruction issued by its Transmission Operator.
R5.	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6.	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7.	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R8.	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9.	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10.	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R11.	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12.	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform in accordance with its Reliability Coordinator's SOL methodology its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18.	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19. Reserved.				
R20.	N/A	N/A	The Transmission Operator had data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time	The Transmission Operator did not have data exchange capabilities with its Reliability Coordinator, Balancing Authority, and identified entities for performing Real-time

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, as specified in the Requirement.	monitoring and Real-time Assessments as specified in the Requirement.
R21.	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality;

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R22. Reserved.				
R23.	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions, but did not have redundant and diversely routed data exchange infrastructure	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis functions as specified in the Requirement.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			within the Balancing Authority's primary Control Center, as specified in the Requirement.	
R24.	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, initiated action to restore the redundant functionality in	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	functionality in more than 2 hours and less than or equal to 4 hours.	more than 4 hours and less than or equal to 6 hours.	more than 6 hours and less than or equal to 8 hours.	Requirement R23 for redundant functionality at least once every 90 calendar days but, following an unsuccessful test, did not initiate action within 8 hours to restore the redundant functionality.
R25.				The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

D. Regional Variances

None.

E. Associated Documents

The Project 2014-03 SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-001-3. Docket No. RM15-16-000. Order No. 817.	Approved
4	February 9, 2017	Adopted by Board of Trustees	Revised
4	April 17, 2017	FERC letter Order approved TOP-001-4. Docket No. RD17-4-000	
5	TBD	Adopted by Board of Trustees	R19 and R22 retired under Project 2018-03 Standards Efficiency Review Retirements
6	TBD	Adopted by the Board of Trustees	Revised

~~Guidelines and Technical Basis~~

~~None.~~

~~Rationale~~

~~Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.~~

~~Rationale for Requirement R3:~~

~~The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.~~

~~Rationale for Requirement R10:~~

~~New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.~~

~~The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.~~

~~The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.~~

~~The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:~~

- ~~OPA;~~
- ~~Real-time Assessments (RTA);~~

- ~~Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and~~
- ~~Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.~~

~~TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.~~

~~The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.~~

~~Rationale for Requirement R13:~~
~~The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.~~

~~Rationale for Requirement R14:~~
~~The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.~~

~~Rationale for Requirements R16 and R17:~~
~~In response to IERP Report recommendation 3 on authority.~~

~~**Rationale for Requirement R18:**~~
~~Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.~~

~~**Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):**~~
~~[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]~~

~~The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).~~

~~Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.~~

~~The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.~~

~~Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.~~

~~**Rationale for Requirement R21:**~~
~~The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).~~

~~A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data~~

~~exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.~~

~~**Rationale for Requirements R22 and R23:**~~
~~[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]~~

~~The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).~~

~~Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.~~

~~The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.~~

~~Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.~~

~~**Rationale for Requirement R24:**~~
~~The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).~~

~~A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.~~

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 - Establish and Communicate System Operating Limits
- FAC-003-5 - Transmission Vegetation Management
- PRC-002-3 - Disturbance Monitoring and Reporting Requirements
- PRC-023-5 - Transmission Relay Loadability
- PRC-026-2 - Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards (“NERC Glossary”)
- Definition of System Operating Limit in the NERC Glossary

Requested Retirement(s)

- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 - Establish and Communicate System Operating Limits
- FAC-003-4 - Transmission Vegetation Management
- PRC-002-2 - Disturbance Monitoring and Reporting Requirements
- PRC-023-4 - Transmission Relay Loadability
- PRC-026-1 - Relay Performance During Stable Power Swings
- TOP-001-5 - Transmission Operations
- IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms “System Voltage Limit” and “System Operating Limit” is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms “System Voltage Limit” and “System Operating Limit” shall become effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of

the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is twenty-four (24) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2, FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-5, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-003-5, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC-002-2, PRC-023-4, and PRC-026-1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
  - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
  - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator.

- *PRC-023-4: Time Period to address new designations is retained:*
    - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- *PRC-002-3, Requirement R5*
    - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3.
- *PRC-023-5*
    - Each Planning Coordinator shall conduct its first assessment under PRC-023-5 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4, whichever occurs first.
- *PRC-026-2*
    - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they must complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
    - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
    - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- FAC-011-4 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 - Establish and Communicate System Operating Limits
- ~~CIP-014-3 Physical Security~~
- FAC-003-5 - Transmission Vegetation Management
- ~~FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~
- PRC-002-3 - ~~-~~Disturbance Monitoring and Reporting Requirements
- PRC-023-5 - Transmission Relay Loadability
- PRC-026-2 - Relay Performance During Stable Power Swings
- TOP-001-6 - Transmission Operations
- IRO-008-3 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary ~~of Terms Used in NERC Reliability Standards~~

Requested Retirement(s)

- FAC-010-3 - System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 - System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 - Establish and Communicate System Operating Limits
- ~~CIP-014-2 Physical Security~~
- FAC-003-4 - Transmission Vegetation Management
- ~~FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~
- PRC-002-2 -~~-~~ Disturbance Monitoring and Reporting Requirements
- PRC-023-4 - Transmission Relay Loadability
- PRC-026-1 - Relay Performance During Stable Power Swings
- TOP-001-5 - Transmission Operations
- IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments
- Currently-effective definition of System Operating Limit

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3, ~~PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective the first day of the first calendar quarter that is ~~twelve ~~twenty-four (24~~12~~) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3, ~~PRC-002-3, PRC-023-5, PRC-026-2, TOP-001-6, IRO-008-3 and the NERC Glossary terms "System Voltage Limit" and "System Operating Limit" shall become effective on the first day of the first calendar quarter that is ~~twelve ~~twenty-four (~~12~~24) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, FAC-014-2~~, CIP-014-2~~, FAC-003-4, ~~FAC-013-2, ~~PRC-002-2, PRC-023-4, and PRC-026-1, TOP-001-~~6~~5, IRO-008-3 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3~~, CIP-014-3~~, FAC-003-5, ~~FAC-013-3,~~ PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

Prior Implementation Plans

Unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4~~, CIP-014-2~~, PRC-002-2, PRC-023-4, and PRC-026~~05~~-~~3~~1~~6~~ are incorporated herein by reference and shall remain applicable to FAC-003-5, ~~CIP-014-3, ~~PRC-002-3, PRC-023-5, and PRC-026-2. The following is a description of the elements from prior implementation plans that remain applicable without modification:

- *FAC-003-5: Newly Designated Lines time period*
  - A line operated below 200kV and identified in the Applicability under 4.2 becomes subject to this standard the later of: 1) 12 months after the date the Planning Coordinator, Transmission Planner or WECC identified the line in Applicability under 4.2, or 2) January 1 of the planning year when the line is forecasted to be identified in Applicability under 4.2. A line operating below 200kV identified in Applicability under 4.2 may be removed from that designation due to system improvements, changes in generation, changes in loads, or changes in studies, and analysis of the network.
- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Initial Date:*
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date of PRC-002-2.

- *PRC-002-3 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: Time Period to Address New Designations:*
  - Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator.
- *PRC-023-4: Time Period to address new designations is retained:*
  - Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6 shall meet R1 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additional Provisions

The following are additional implementation provisions to address revisions in the Reliability Standards that require new or different actions by the same or different entities than the prior version of the Reliability Standards required.

- ~~*FAC-013-2*~~
  - ~~Following effective date of FAC-013-3, the Planning Coordinator shall update their methodology and perform their assessment either:~~
    - ~~Within the calendar year the standard becomes effective if the assessment was not completed that calendar year under FAC-013-2~~
    - ~~Within the next calendar year after the standard is effective if the assessment had been completed within that calendar year under FAC-013-2~~
- ~~*CIP-014-3*~~
  - ~~Following effective date of FAC-013-3, the Transmission Owner shall perform the risk assessment Required in Requirement R1 within~~
    - ~~30 calendar months of its last assessment if it had identified one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection in that prior assessment; or~~
    - ~~60 calendar months of its last assessment if it had not identified any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.~~
- *PRC-002-3, Requirement R5*
  - Reliability Coordinators in the Eastern Interconnect shall be fully compliant with

Requirement R5 within six (6) months of the effective date of PRC-002-3.

- *PRC-023-~~4~~5*
    - Each Planning Coordinator shall conduct ~~t~~its first assessment under PRC-023-~~4~~5 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-~~3~~4, whichever occurs first.
- *PRC-026-2*
    - Each Planning Coordinator shall complete Requirement R1 within the calendar year of the effective date unless they have already completed Requirement R1 under PRC-026-1 for that calendar year, in which case they m~~o~~ust complete Requirement R1 within the following year.
- *FAC-014-3, Requirement R6*
    - Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment.
- *FAC-014-3, Requirements R7 and R8*
    - Each Planning Coordinator and Transmission Planner shall comply with Requirements R7 and R8 within one year of the effective date of the standard.

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3).
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2).
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3).
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2).

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with

requirement R2 are expected to “provide” a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that “provide” for meeting the performance criteria denoted in FAC-011 R2 and subparts. Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.

These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.

2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.

3. The TOP would communicate those SOLs to System Operators.

4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that “provide” for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO

standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the Project 2014-03 Whitepaper provided clarity on the SOL concept,

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the SDT posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use

maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed requirement R6 in proposed Reliability Standard FAC-014-3 to address that issue.

As discussed in detail below, the SDT determined that references to "most limiting criteria" and "acceptable reliability criteria", and the manner in which the "specified system configuration" and the "pre- and post-contingency" phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

<u>Most limiting Criteria</u> – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria." Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most

limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

<u>Acceptable Reliability Criteria</u> – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

<u>Specified System Configuration</u> – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

<u>Pre- and Post-Contingency</u> – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

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assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

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NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

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Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL-") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3).
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2).
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3).
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2).

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with

requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts. Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.

These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]

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[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

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[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

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As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

review team recognized that while the Project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

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The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

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Unlike the existing SOL definition, the proposed definition includes the phrase “used in Bulk Electric System operations” to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed requirement R6 in proposed Reliability Standard FAC-014-3 to address that issue.~~The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.~~

As discussed in detail below, the SDT determined that references to “most limiting criteria” and “acceptable reliability criteria”, and the manner in which the “specified system configuration” and the “pre- and post-contingency” phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the “most limiting criteria” concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the “most limiting criteria.” Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the “most limiting criteria” concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

<u>Acceptable Reliability Criteria</u> – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

<u>Specified System Configuration</u> – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

<u>Pre- and Post-Contingency</u> – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA)

and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, “could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES.” The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC’s SOL methodology. There is no need to mention IROLs in the definition of SOL.

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[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating “the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC’s characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability.”

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for

the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

Mapping Document for FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of ~~a new FAC-015-1 Reliability Standard and~~ revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT’s ~~proposal for a new FAC-015-1 Reliability Standard, along with the~~ proposed revisions contained in FAC-011-4 and FAC-014-3~~,~~ represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL ~~M~~methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-01~~5~~4-~~1~~3, Requirement~~s R1~~ R7 ~~– R3 ensure~~is intended to provide a mechanism for ~~that~~ Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator’s (RC’s) SOL ~~M~~methodology. FAC-~~015~~014-~~1~~3, Requirement~~s~~ R~~1 – R3~~7 ~~respectively~~ addresses Facility Ratings, System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. ~~These~~ Therefore, this requirement~~s~~ focuses on the three components of SOLs used in operations and facilitates continuity between operations and planning. Implementing the process~~es~~ required in FAC-~~015~~014-~~1~~ 3 Requirement~~s~~ R~~1 – R3~~7 ensures Planning Coordinators (PC) and Transmission Planners (TP) use, or provide a technical rationale why they don’t use Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator’s SOL ~~M~~methodology.

FAC-~~015~~014-~~1~~3, Requirement ~~R4~~ R8 requires PCs and TPs to communicate ~~any~~ pertinent information on Corrective Action Plans (CAP) developed to address any instability~~, Cascading or uncontrolled separation, along with key supporting information,~~ identified in ~~the~~ Planning Assessments of the Near-Term Transmission Planning Horizon to the RC~~s~~ and to impacted Transmission Operators (TOPs). This information may be useful to RCs and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements ~~R1~~ R7 ~~–~~and R~~4~~8 of FAC-014-3~~5~~, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment of the Near-Term Transmission Planning Horizon are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL ~~M~~methodology (FAC-011-4 ~~& FAC-014-3~~). Furthermore, potentially critical stability information is communicated by planners to operators resulting ~~. The result is~~ an improvement in reliability by ~~ensuring~~ increasing continuity between planning and operations not currently provided for in the existing body of NERC Reliability Standards.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events) Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-~~015~~014-~~1~~3 Requirement R7 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1. Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2. State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL ~~M~~methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL ~~M~~methodology. In the proposed construct, PCs and TPs develop Planning Assessments effectively bound by the RC's SOL methodology. These Planning Assessments then identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via ~~FAC-015-1, Requirement R4. IROLs are established by the RC as required by FAC-014-3.~~the distribution of the Planning Assessments (in accordance with IRO-017-1 Requirement R3) TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability

			Operating Limit (IROL).
R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2. Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1:** **Note: 'b'**	
R2.3.2. System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1:** **Note: 'e'**	
R2.4. To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1:** **Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

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all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

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	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

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	for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3. The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

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R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

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	achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

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R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL ~~M~~methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as “Requirements Recommended for Retirement” in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as “More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

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	R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3. Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

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Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” The title of FAC-011-4 is “System Operating Limits Methodology for the Operations Horizon”. Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. <u>FAC-011-4 Requirement R2</u>: Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. <u>Operational Planning Analysis</u> is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R8 and Part 8.1. R8. Each Reliability Coordinator shall include in its SOL methodology 8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	FAC-011-4 Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: 6.1. System performance for no Contingencies	The items in approved FAC-011-3, Requirement R2.1 and R2.2 are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposedTOP-001-6 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.4 divide system performance requirements for the no contingency state (N-0) into each of the

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	demonstrates the following: 6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.. 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System	three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in

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	adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded. 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. System performance for the single Contingencies listed in Part 5.1	Part 6.2.4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly identify that, in determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is an acceptable only after all other available System adjustments have been made. TOP-001-5, Requirement R25 and IRO-008-3, Requirement R7 support FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to determine SOL

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	demonstrates the following: 6.2.1. Steady state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met.	exceedances in accordance with its RC's the SOL methodology.

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	6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	

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	TOP-001-6, Requirement R25. R25. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis. . IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal	FAC-011-4, Requirement R5, Part 5.1 5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4 Requirement R5, Part 5.1.

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Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	(whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; or • single pole block, with, in a monopolar or bipolar high voltage direct current system.	FAC-011-4 Requirement R5, Part 5.1. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability;	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated

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at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	4.1.2. transient voltage response; 4.1.3. angular stability; and 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages. 4.5. Describe the level of detail that is required for the study model(s), including	in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are

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	the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential	addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are

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	System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-002-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit	governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made.

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	(SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or	Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly

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	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.4 albeit with improved language for clarity. FAC-011-4 Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses: R6.4 In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.

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FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC

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		areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.1. Specify the following single Contingency events: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• generator; • transmission circuit; • transformer; • shunt device; • single pole block in a monopolar or bipolar high voltage direct current system. 5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any. 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-	FAC-011-4, Requirement R5, Part 5.3 R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational	FAC-011-4, Requirement R5, Part 5.3 and FAC-014-3 Requirement R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-014-3, Requirement R7, the Planning Coordinator is required to identify and

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014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall: 5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-014-3, Requirement R7, to use in determining stability limits. FAC-014-3 Requirement R7: R7. Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and	annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.3 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient	

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	voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion modeled of the Reliability Coordinator Area, and the critical modeling details from other Reliability Coordinator	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

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	Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL methodology the method	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in

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configuration, generation dispatch and Load level	for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An*	proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement

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	evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"	R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement R8, Part 8.2 R8.2 Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R8, Part 8.2.
FAC-011-3, Requirement R4 and Requirement R4.1:	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4:	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-

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R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	R9. Each Reliability Coordinator shall provide its SOL methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request. 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within the same; Interconnection; 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's methodology to requesting RCs in Part 9.1 and to those entities that are directly impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL methodology within 30 days of the request if they indicate a reliability-related need for it. 8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2. R9. Each Reliability Coordinator shall provide its SOL methodology to:	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning

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Reliability Coordinator's Reliability Coordinator Area.	9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	within the RC Area rather than just because it has a model for an RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area; and	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

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FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL ~~M~~methodology) within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” The title of FAC-011-4 is “System Operating Limits Methodology for the Operations Horizon”. Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations

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		horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL ~~M~~methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R~~7~~8 and Part ~~7~~8.1. R~~7~~8. Each Reliability Coordinator shall include in its SOL ~~M~~methodology ~~7~~8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system	FAC-011-4 Requirement R6 and Parts 6.1, 6.2, 6.3, and 6.4. R6. Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~:	The items in approved FAC-011-3, Requirement R2.1 and R2.2 ~~are addressed~~are addressed through proposed FAC-011-4, Requirement R6 and its subparts as well as proposed ~~FAC-014-3 R7R6~~TOP-001-6 R25 and IRO-008-3 R7. While FAC-011-3 R2.1 focuses on pre-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, FAC-011-4 Requirement R6 Parts R6.1, 6.1.1, 6.1.2, 6.1.3 and 6.1.~~3~~ 4 divide system performance requirements for the ~~pre-~~no

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conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	6.1. ~~The actual pre-~~System performance for no Contingenc~~y~~ies ~~state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following: 6.1.1. Steady state ~~F~~flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time	contingency state (N-0) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and uncontrolled separation were included in Part 6.1.~~3~~4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. Similarly, FAC-011-3 Requirement R2.2 focuses on post-contingency BES performance for all three types of SOL (Facility Ratings, System Voltage Limits and stability limits) together, while FAC-011-4 Requirement R6 Parts 6.2, 6.2.1, 6.2.2, 6.2.3 and 6.2.~~3~~ 4 divides system performance requirements for the evaluation of Contingencies against the pre-Contingency state for the anticipated post-Contingency state (N-1) or (N-x) into each of the three categories (Facility Ratings, System Voltage Limits, and stability limits) into its own subpart for clarity. Cascading and

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	duration of those Emergency Ratings.. 6.1.2. Steady state ~~V~~voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits. 6.1.3. Predetermined stability limits are not exceeded. ~~6.1.3.~~6.1.4. Instability, Cascading or	uncontrolled separation were included in Part 6.2.~~3~~4. The proposed language adds clarity by clearly identifying expectations relative to normal and emergency Facility Ratings and System Voltage Limits. In a similar fashion, Part 6.3 identifies the minimum requirement for BES performance for those Contingencies identified in FAC-011-4 Requirement R5 Part 5.2 which is to demonstrate "that instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur." FAC-011-4 Proposed Part 6.4 is meant to clearly ~~delineate the system performance requirements related to establishing stability limits using the Contingencies identified in Requirement R5, Part 5.3~~identify that, in determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is ~~a~~an acceptable only after all other available System adjustments have been made.

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	uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.2. ~~The evaluation of potential~~System performance for the single Contingencies listed in Part 5.1~~.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates the following: 6.2.1. Steady state post-Contingency ~~F~~flow through Facilities ~~are~~ within applicable Emergency Ratings.~~,~~	TOP~~FAC~~-001~~1~~4-5~~3~~, Requirement R~~7~~25 and IRO-008-3, Requirement R7~~6~~ support~~s~~ FAC-011-4 Requirement R6 and its parts by requiring TOPs and RCs to ~~use the performance criteria identified~~determine SOL exceedances in accordance with its RC's the SOL ~~M~~methodology.

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	~~provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings.~~ Steady state post-Contingency ~~F~~flow through a Facility must not be above the Facility's highest Emergency Rating. 6.2.2. Steady state post-Contingency ~~V~~voltages are within emergency System Voltage Limits. 6.2.3. The stability performance criteri~~a~~e defined in the Reliability Coordinator's SOL methodology are met.	

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	~~6.2.3.~~6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. 6.3. ~~The evaluation of~~ System performance for applicable ~~the potential~~ Contingencies identified in Part 5.2 ~~against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis)~~ demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk	

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	Electric System- does not occur. ~~6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.~~ 6.~~5~~ 4 In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made. ~~FAC~~TOP-0~~01~~1~~4~~-6~~53~~, Requirement R2~~567~~. R~~6~~25 ~~7~~. Each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational	

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	Planning Analysis. ~~Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances in accordance with its Reliability Coordinator's SOL Methodology when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~. IRO-008-3, Requirement R7. R7. Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3	FAC-011-4, Requirement R5, Part 5.1~~.1~~	The requirements in approved FAC-011-3 were consolidated into a single requirement

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R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	5.1 Specify the following single Contingency events 5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; or • single pole block, with ~~Normal Clearing~~, in a monopolar or bipolar high voltage direct current system.	in proposed FAC-011-4 Requirement R5, Part 5.1~~.1~~. FAC-011-4 Requirement R5, Part 5.1~~.1~~. is also referenced in FAC-011-4 Requirement R6, Part 6.2 for the system performance requirements for anticipated post-contingency state.
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or	The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-

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supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	criteria shall, at a minimum, include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. ~~unit~~ angular stability; and 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator ~~.~~Areas. 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System	requirements of Requirement R2, which addresses the establishment of SOLs that “provide a certain level of BES performance”. “BES performance” as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). ~~If SOL exceedance is occurring, the system is not performing reliably.~~ Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is “studied” at least once every 30 minutes. Additionally, per the TOP standards, SOL exceedance triggers the development and implementation of an

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	conditions including any changes to System topology such as Facility outages~~;~~. 4.5. Describe the level of detail that is required for the study model(s), including the portion ~~extent~~modeled of the Reliability Coordinator Area, ~~as well as~~ and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of	Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL ~~M~~methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary manual actions taken by the System Operator to configure the system in a

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	Operating Plans as denoted in the following standards: ~~1. FAC-014-3, Requirement R8: In addressing any potential or actual SOL exceedances, each Reliability Coordinator and Transmission Operator shall allow for Non-Consequential Load Loss within their Operating Plan only if all other means of System adjustments have been exhausted to prevent:~~ ~~• equipment damage, or~~ ~~• instability, Cascading, uncontrolled separation~~ ~~4.~~1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. ~~5.~~2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the	manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The SDT has proposed retaining the concept captured in FAC-011-3 Requirement R2.3.2 in proposed FAC-011-4 Requirement R6.~~5~~ 4 albeit with improved language for clarity. Rather than specifying the operating conditions where interruption of network customers is allowed, the SDT has clarified when planned manual load shedding is acceptable. This recognizes that RTAs must be conducted every 30 minutes (i.e. system is constantly being evaluated and readjusted at least every 30 minutes) as well as incorporating the principle that load shed will be a measure of last resort as supported by FERC Orders (e.g. FERC Order 693 para 591.) While a System Operator

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	Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). ~~6.~~3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. ~~7.~~4. TOP-~~01~~2002-~~3~~4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. ~~8.~~5. IRO-008-~~2~~3, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while	maintains authority to take whatever action is needed to ensure reliability, entities should not "plan" to shed load until all other system adjustments (e.g. generation commitment, generation redispatch, transmission system adjustments, interruptible loads, etc.) have been made. Regarding FAC-011-3 Requirement R2.4, the need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances. In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that

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	considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. ~~9.~~6. IRO-008-~~2~~3, Requirement R3: Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). ~~10.~~7. IRO-008-~~2~~3, Requirement R5: Each Reliability Coordinator shall notify, in accordance with its SOL ~~M~~methodology impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards and proposed FAC-011-4 Requirement 6.~~5~~4, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4.

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	The SDT has proposed retaining the concept captured in FAC-011-3 R2.3.2 in proposed FAC-011-4 R6.~~5~~ 4 albeit with improved language for clarity. FAC-011-4 Each Reliability Coordinator shall include the following performance framework in its SOL ~~M~~methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses~~, at a minimum, the following Bulk Electric System performance criteria~~: R~~.~~6.~~5~~ 4 In determining the System's response to any Contingency identified in ~~Parts 5.1 through 5.3~~Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.	
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following,	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single

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along with any reliability margins applied for each: R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion ~~extent~~modeled of the Reliability Coordinator Area, ~~as well as~~ and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to

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		wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)~~ for the area under study~~. The SOL ~~M~~methodology for each set shall: 5.1. Specify the following single Contingency events~~ for use in determining stability limits and performing OPAs and RTAs~~: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

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	• generator; • transmission circuit; • transformer; • shunt device; • single pole block~~, with Normal Clearing,~~ in a monopolar or bipolar high voltage direct current system. 5.2. ~~Identify any~~Specify additional single or multiple Contingency events or types of Contingency events, if any ~~for use in performing OPAs and RTAs~~. ~~5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.~~ 5.~~4~~3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, to use in determining stability limits.	

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FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	FAC-011-4, Requirement R5, Part 5.~~4~~3 R5. Each Reliability Coordinator shall identify in its SOL ~~M~~methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs)~~ for the area under study~~. The SOL ~~M~~methodology for each set shall: 5.~~4~~3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator in accordance with FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, to use in determining stability limits. FAC-~~015~~014-~~1~~ 3 Requirement ~~R4~~R7: R7. ~~R4.~~ Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for	FAC-011-4, Requirement R5, Part 5.~~4~~ 3 and FAC-~~015~~014-~~1~~ 3 Requirement ~~R4~~ R7 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1. In FAC-~~015~~014-~~1~~3, Requirement ~~R4~~R7, the Planning Coordinator is required to identify and annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon~~any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R4~~, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.~~4~~ 3 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

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	Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage	

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	instability, angular instability including generating unit loss of synchronism and/or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan	

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	~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);~~ ~~4.2 The associated stability criteria used as part of determining the instability;~~ ~~4.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;~~ ~~4.4 A description of the studied system conditions when the instability, Cascading or uncontrolled separation was identified;~~ ~~4.5 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability,~~	

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	~~Cascading or uncontrolled separation; and~~ ~~4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.~~	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the portion ~~extent~~modeled of the Reliability Coordinator Area, ~~as well as~~ and the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 and Part 4.7 R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by adding Part 4.7 which restricts

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	method for determining the stability limits to be used in operations. The method shall: 4.6 Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. 4.7 State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding (UVLS) Programs are not allowed in the establishment of stability limits.	the use of UFLS programs and UVLS Programs in the establishment of stability limits.
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL ~~M~~methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement

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	conditions including any changes to System topology such as Facility outages. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not*	R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.

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	limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"	
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.	FAC-011-4, Requirement ~~R7~~R8, Part ~~7~~8.2 ~~R6~~R8.2 Criteria for determining when ~~violating~~ exceeding a SOL qualifies as ~~an~~ exceeding an IROL and criteria for developing any associated IROL T_v.	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement ~~R7~~R8, Part ~~7~~8.2.
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:	FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4: R9. Each Reliability Coordinator shall provide its SOL ~~M~~methodology to: 9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R9, Parts 9.1, 9.2.1 and 9.2.4. FAC-011-4 Requirement 9 was re-organized to address timely provisions of the RC's ~~M~~methodology to requesting RCs in Part 9.1 and to those entities that are directly

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R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.1. Each adjacent Reliability Coordinator within the same~~;~~ Interconnection; 9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.	impacted and therefore must be informed for any change, in Part 9.2. Non-adjacent RCs, which are addressed in Parts 9.1 and 9.2.4., do not require communication of the SOL ~~M~~methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Parts 9.1 and 9.2.4 for non-adjacent RCs to obtain the SOL ~~M~~methodology within 30 days of the request if they indicate a reliability-related need for it. ~~Part 9.2 also includes a requirement to provide the SOL Methodology as soon as practicable if a change was necessary to address a reliability issue. This provides flexibility for an RC to make reliability needed changes to its SOL Methodology quickly.~~8
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.2. R9. Each Reliability Coordinator shall provide its SOL ~~M~~methodology to:	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area rather than just because it has a model for an RC Area.

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Reliability Coordinator's Reliability Coordinator Area.	9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;	
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R9, Part 9.2 and subpart 9.2.3. R9. Each Reliability Coordinator shall provide its new or revised SOL ~~M~~methodology to: 9.2. Each of the following entities prior to the effective date of the SOL methodology: 9.2.3 Each Transmission Operator within its Reliability Coordinator Area; and	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R9, Part 9.2. and Subpart 9.2.3.

Mapping Document for FAC-014-3

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
<u>FAC-014-2, Requirement R1</u> R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL methodology.	<u>Requirements R1, R2, and R4 of FAC-014-3</u> R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology. R4. Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

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		not ensure that the TOP's SOL was consistent with its SOL methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
<u>FAC-014-2, Requirement R2</u> R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	<u>FAC-014-3, Requirement R2</u> R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

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Coordinator Area that are consistent with its Reliability Coordinator's SOL methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL methodology.	FAC-011-4, Requirement R9, Part 9.2, Subpart 9.2.2 FAC-014-3, Requirement R6 FAC-011-4, Requirement R9, Part 9.2: **R9.** Each Reliability Coordinator shall provide its SOL methodology to: **9.2** Each of the following entities prior to the effective date of the SOL methodology: **9.2.2** Each Planning Coordinator and Transmission Planner that is responsible for	The SDT is proposing a construct that does not make use of an SOL methodology applicable to the planning horizon or the establishment of SOLs consistent with the PC's SOL methodology. The PCs and TPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL methodology through FAC-011-4, Requirement R9, Part 9.2.2. By having the RC's SOL methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria

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	planning any portion of the Reliability Coordinator Area; FAC-014-3 Requirement R6: **R6.** Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of the Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability criteria specified described in its respective Reliability Coordinator's SOL methodology. • The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale Each Planning Coordinator shall provide a technical rationale for any exceptions to each affected Transmission Planner, Transmission Operator and Reliability Coordinator. • The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a	for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. Proposed FAC-011-4 and FAC-014-3 represent an improvement for planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-014-3, Requirement R6 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those described within the RC's SOL methodology. FAC-014-3, Requirement R6 addresses the three components of SOLs used in operations and thus facilitates continuity between operations and planning, which is conducive to improved reliability.

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	technical rationale Each Transmission Planner shall provide a technical rationale for any exceptions to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator and each impacted Transmission Planner within its	While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs, which addresses RC-to-RC communication and coordinated operations issues.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the deriviation of the stability limit or the IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated critical Contingency(ies); 5.2.5. A description of system conditions associated with the stability limit or IROL; and 5.2.6. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning	

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	Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. 5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an (IROL) and its associated critical contingencies at least once every twelve calendar months. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that	

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	require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages. 1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
<u>FAC-014-2, Requirement R5, R5.2</u> R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 <u>FAC-014-3, Requirement R3</u> R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator.	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	1. FAC-014-3, Requirements R7 2. TPL-001-4, Requirement R8 FAC-014-3 Requirements R7 (Also see the translation above for Requirements R3 and R4) **R7.** Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include: **7.1** The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any other planned mitigation actions); **7.2** The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular	Provision of important planning study information to TOPs and RCs is preserved in FAC-014-3, Requirement R7, which requires the PC and TP to annually communicate information for Corrective Action Plans developed to address any instability identified in its Planning Assessments to each impacted TOP and RC. The subparts of Requirement R7 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a

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	instability including generating unit loss of synchronism, or unacceptable damping); **7.3** The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria); **7.4** The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan; **7.5** The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan. TPL-001-4, Requirement **R8**: **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. **8.1.** If a recipient of the Planning Assessment results provides documented comments on the	PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
<u>FAC-014-2, Requirement R6</u> R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	<u>FAC-014-3, Requirement R7</u> (See the Translation above for Requirements R5.3 and R5.4)	FAC-014-3, Requirement R7 covers the content of FAC-014-2, Requirement R6.1 and improves upon it as follows: • FAC-014-3, Requirement R7 addresses not only the identification of multiple contingencies that result in stability criteria violation, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6.1, the FAC-014-3, Requirement R7 ensures the type of instability, the associated stability criteria, the associated planning event contingencies, the associated system conditions & Facilities, and Corrective Action Plans developed for its mitigation are

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		communicated by the PC to the appropriate TOP and RC. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-014-3, Requirement R7 because all instances of instability identified by the PC are to be communicated to the impacted TOP and RC. Further, it may be noted that FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-014-3, Requirement R7 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

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Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R1	TOP-001-6, Requirement R1	No modifications made.
TOP-001-5, Requirement R2	TOP-001-6, Requirement R2	No modifications made.
TOP-001-5, Requirement R3	TOP-001-6, Requirement R3	No modifications made.
TOP-001-5, Requirement R4	TOP-001-6, Requirement R4	No modifications made.
TOP-001-5, Requirement R5	TOP-001-6, Requirement R5	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R6	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R7	No modifications made.
TOP-001-5, Requirement R8	TOP-001-6, Requirement R8	No modifications made.
TOP-001-5, Requirement R9	TOP-001-6, Requirement R9	No modifications made.
TOP-001-5, Requirement R10	TOP-001-6, Requirement R10	No modifications made.
TOP-001-5, Requirement R11	TOP-001-6, Requirement R11	No modifications made.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R12	TOP-001-6, Requirement R12	No modifications made.
TOP-001-5, Requirement R13	TOP-001-6, Requirement R13	No modifications made.
TOP-001-5, Requirement R14	TOP-001-6, Requirement R14	No modifications made.
TOP-001-5, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	TOP-001-6, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency on SOL exceedances within an RC's area between the RC and its TOPs. Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R16	TOP-001-6, Requirement R16	No modifications made.
TOP-001-5, Requirement R17	TOP-001-6, Requirement R17	No modifications made.
TOP-001-5, Requirement R18	TOP-001-6, Requirement R18	No modifications made.
TOP-001-5, Requirement R19	TOP-001-6, Requirement R19	No modifications made.
TOP-001-5, Requirement R20	TOP-001-6, Requirement R20	No modifications made.
TOP-001-5, Requirement R21	TOP-001-6, Requirement R21	No modifications made.
TOP-001-5, Requirement R22	TOP-001-6, Requirement R22	No modifications made.
TOP-001-5, Requirement R23	TOP-001-6, Requirement R23	No modifications made.
TOP-001-5, Requirement R24	TOP-001-6, Requirement R24	No modifications made.

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Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R1	TOP-001-6, Requirement R1	No modifications made.
TOP-001-5, Requirement R2	TOP-001-6, Requirement R2	No modifications made.
TOP-001-5, Requirement R3	TOP-001-6, Requirement R3	No modifications made.
TOP-001-5, Requirement R4	TOP-001-6, Requirement R4	No modifications made.
TOP-001-5, Requirement R5	TOP-001-6, Requirement R5	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R6	No modifications made.
TOP-001-5, Requirement R6	TOP-001-6, Requirement R7	No modifications made.
TOP-001-5, Requirement R8	TOP-001-6, Requirement R8	No modifications made.
TOP-001-5, Requirement R9	TOP-001-6, Requirement R9	No modifications made.
TOP-001-5, Requirement R10	TOP-001-6, Requirement R10	No modifications made.
TOP-001-5, Requirement R11	TOP-001-6, Requirement R11	No modifications made.

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TOP-001-5, Requirement R12	TOP-001-6, Requirement R12	No modifications made.
TOP-001-5, Requirement R13	TOP-001-6, Requirement R13	No modifications made.
TOP-001-5, Requirement R14	TOP-001-6, Requirement R14	No modifications made.
TOP-001-5, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	TOP-001-6, Requirement R15 **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded in accordance with its Reliability Coordinator's SOL methodology. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*	The inclusion of the terminology "in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. Proposed FAC-011-4 R7 requires the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure communication consistency on SOL exceedances within an RC's area between the RC and its TOPs. ~~This communication could range from simply RC and TOP sharing via ICCP output from the real-time monitoring and RTCA output to operator to operator communications.~~

Standard TOP-001-6		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Without the addition of this reference, there is no joint method for use by the RC and TOP when communicating with regard to SOL exceedances.
TOP-001-5, Requirement R16	TOP-001-6, Requirement R16	No modifications made.
TOP-001-5, Requirement R17	TOP-001-6, Requirement R17	No modifications made.
TOP-001-5, Requirement R18	TOP-001-6, Requirement R18	No modifications made.
TOP-001-5, Requirement R19	TOP-001-6, Requirement R19	No modifications made.
TOP-001-5, Requirement R20	TOP-001-6, Requirement R20	No modifications made.
TOP-001-5, Requirement R21	TOP-001-6, Requirement R21	No modifications made.
TOP-001-5, Requirement R22	TOP-001-6, Requirement R22	No modifications made.
TOP-001-5, Requirement R23	TOP-001-6, Requirement R23	No modifications made.
TOP-001-5, Requirement R24	TOP-001-6, Requirement R24	No modifications made.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore, a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	Moderate	High	Severe
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, of Requirement R5 into its SOL methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3 of Requirement R5 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R6 and Requirement R8 which requires performance framework and description of identifying Interconnection Reliability Operating Limits (IROLs) within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to include a requirement for Part 7.2.	The Reliability Coordinator failed to include a requirement for Part 7.1.	The Reliability Coordinator failed to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL methodology. OR The Reliability Coordinator failed to include Part 8.2 (criteria for developing any associated IROL T_v) in its SOL methodology.	The Reliability Coordinator failed to include Parts 8.1 and 8.2 in its SOL methodology.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.5. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008~~13~~-3~~2~~, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore, a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL ~~M~~methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL ~~M~~methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL ~~M~~methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 ~~or 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, ~~or 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL ~~M~~methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3~~, and 5.4~~ of Requirement R5 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R2 which requires performance criteria within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance ~~criteria~~ framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL ~~M~~methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-011-3, Requirement R6 and Requirement R8 which requires performance framework and description of identifying Interconnection Reliability Operating Limits (IROLs) within its methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to include performance framework could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to include a requirement for Part 7.2.	The Reliability Coordinator failed to include a requirement for Part 7.1.	The Reliability Coordinator failed to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R~~7~~8	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R~~7~~8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part ~~7~~8.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL ~~M~~methodology. OR The Reliability Coordinator failed to include Part ~~7~~8.2 (criteria for developing any associated IROL T_v) in its SOL ~~M~~methodology.	The Reliability Coordinator failed to include Parts ~~7~~8.1 and ~~7~~8.2 in its SOL ~~M~~methodology.

VSL Justifications for FAC-011-4, Requirement R~~7~~8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.~~7~~5. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

~~VRF Justifications for FAC-011-4 Requirement R8~~	
~~Proposed VRF~~	~~Medium~~
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements (Parts) so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~VSLs for FAC-011-4, Requirement R8~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.~~	~~The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.~~

~~VSL Justifications for FAC-011-4, Requirement R8~~	
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL is worded consistently with the corresponding requirement.~~

~~**FERC VSL G4**~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~The proposed VSL is not based on a cumulative number of violations.~~

VRF Justifications for FAC-011-4 Requirement R9	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, ~~and FAC-013-2, Requirement R2~~ which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-011-4, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 but was late by less than or equal to 10 calendar days	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL ~~M~~methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL ~~M~~methodology to a requesting Reliability

			Coordinator in accordance with Requirement R9, Part 9.1.

VSL Justifications for FAC-011-4, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit ~~M~~methodology ("SOL ~~M~~methodology")~~ as established in FAC-011-4~~.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the Reliability Coordinator needs such information to perform its reliability functions.	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator failed to determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL ~~M~~methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary, and therefore, a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.~~65~~6.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.~~65~~6.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	Medium~~High~~
The reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R6 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.	
~~**FERC VRF G1 Discussion**~~ ~~Guideline 1- Consistency with Blackout Report~~	~~The VRF is consistent with the conclusions of the final Blackout Report.~~
~~**FERC VRF G2 Discussion**~~ ~~Guideline 2- Consistency within a Reliability Standard~~	~~The requirement has no sub-requirements so a single VRF was assigned.~~
~~**FERC VRF G3 Discussion**~~ ~~Guideline 3- Consistency among Reliability Standards~~	~~A VRF of high for this requirement is consistent with approved Reliability Standard FAC-011-2 Requirement R2 which requires a minimum level of performance.~~
~~**FERC VRF G4 Discussion**~~ ~~Guideline 4- Consistency with NERC Definitions of VRFs~~	~~Failing to use Bulk Electric System performance criteria in its OPAs, RTAs, and Real-time monitoring could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.~~
~~**FERC VRF G5 Discussion**~~ ~~Guideline 5- Treatment of Requirements that Co-~~	~~The requirement contains one objective, therefore a single VRF is assigned.~~

~~mingle More than One Obligation~~	

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings, System steady state voltage limits or stability criteria than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology, but failed to provide a technical rationale for allowing the use of less limiting Facility Ratings, System Voltage Limits or stability criteria. ~~N/A~~	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that Facility Ratings, System steady state voltage limits or stability criteria used in Planning Assessment are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits or stability described in its respective Reliability Coordinator's SOL methodology.~~A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.~~

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.~~ ~~The requirement is clear and does not contain any ambiguous language.~~
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R7	
Proposed VRF	Medium

The reliability objective of Requirement R5 from approved Reliability Standard FAC-014-2 is now Requirement R7 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R7, Parts 7.1 through 7.5.	The Planning Coordinator or a Transmission Planner communicated the identified instability to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R7, Parts 7.1 through 7.5. OR The Planning Coordinator or a Transmission Planner failed to communicate any identified instability, to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement ~~R5.3 and~~R5.3 and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-1 Requirement R8	
Proposed VRF	Medium

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R8 of the proposed standard. Therefore, the existing VRF of medium was maintained for consistency.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.3 -and 5.4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications for FAC-014-3, Requirement R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in IRO-008. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification for IRO-008-3, Requirement R1

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R1

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R2

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R2

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R3

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R3

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R4

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R4

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R5

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R5

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R6
The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R6
The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	The requirement contains one objective, therefore, a single VRF is assigned.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for IRO-008-3, R7			
Lower	**Moderate**	**High**	**Severe**
			The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in IRO-008. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for IRO-008-3, Requirement R1

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R1

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R2

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R2

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R3

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R3

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R4

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R4

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R5

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R5

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justification for IRO-008-3, Requirement R6

The VRF did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VSL Justification for IRO-008-3, Requirement R6

The VSL did not change from the previously FERC approved IRO-008-2 Reliability Standard.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	The requirement contains one objective, therefore, a single VRF is assigned.

VRF Justifications for IRO-008-3 R7	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for IRO-008-3, R7			
Lower	**Moderate**	**High**	**Severe**
			The Reliability Coordinator failed to use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

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Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TOP-001-6, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R1

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R2

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R3

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R4

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R5

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R6
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R7
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R8
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R9
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R10
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R19
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R19
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R22
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R22
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for TOP-001-6, R25			
Lower	**Moderate**	**High**	**Severe**
			The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-09 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TOP-001-6, Requirement R1

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R1

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R2

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R2

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R3

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R3

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R4

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R4

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R5

The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R5

The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R6
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R6
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R7
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R7
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R8
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R8
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R9
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R9
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R10
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R10
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R11
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R11
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R12
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R12
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R13
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R13
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R14
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R14
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R15
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R15
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R16
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R16
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R17
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R17
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R18
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R18
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R19
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R19
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R20
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R20
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R21
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R21
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R22
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R22
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R23
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R23
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justification for TOP-001-6, Requirement R24
The VRF did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VSL Justification for TOP-001-6, Requirement R24
The VSL did not change from the previously FERC approved TOP-001-5 Reliability Standard.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
NERC VRF Discussion	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirement R2.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for determining SOL exceedances has the potential unintended consequence of creating inconsistencies in determining SOL exceedances which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

VRF Justifications for TOP-001-6 R25	
Proposed VRF	**High**
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore, a single VRF is assigned.

VSLs for TOP-001-6, R25			
Lower	**Moderate**	**High**	**Severe**
			The Transmission Operator failed to use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time monitoring, and Operational Planning Analysis.

Technical Rationale for Reliability Standard FAC-011-4

April 2021

FAC-011-4 – System Operating Limits Methodology for the Operations Horizon

Requirement R1

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1 Part 1.1 in currently-effective FAC-011-3 requires the SOL methodology "be applicable for developing System Operating Limits (SOLs) used in the operations horizon." The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1 Part 1.2 in currently-effective FAC-011-3 requires the SOL methodology to "state that SOLs shall not exceed associated Facility Ratings." Facility Ratings to be used in operations as SOLs are addressed through FAC-011-4 Requirement R2 and therefore, is not addressed as a subpart of R1.

Requirement R1 Part1.3 in currently-effective FAC-011-3 requires the SOL methodology to "include a description of how to identify the subset of SOLs that qualify as IROLs." This language is preserved in Requirement R7.

Requirement R2

R2. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission

Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still the functional entity responsible for determining Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between RCs and their TOPs during operations.

Requirement R3

R3. Each Reliability Coordinator shall include in its SOL methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1.** Require that each BES bus/station have an associated System Voltage Limits, unless its SOL methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;
- **3.2.** Require that System Voltage Limits respect voltage-based Facility Ratings;
- **3.3.** Require that System Voltage Limits are greater than or equal to in-service BES relay settings for under-voltage load shedding systems and Undervoltage Load Shedding Programs;
- **3.4.** Identify the minimum allowable System Voltage Limit;
- **3.5.** Define the method for determining common System Voltage Limits between the Reliability Coordinator and its Transmission Operators, between adjacent Transmission Operators, and between adjacent Reliability Coordinators within an Interconnection;

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within each RC Area. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its RC Area for voltage-based Facility Ratings, voltage instability, voltage collapse and misactuation of relay elements.

Both maximum and minimum limits are required. Maximum limits tend to be associated with equipment/facility limitations. Minimum limits are often used to prevent phenomena associated with minimum voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of “System Voltage Limits”, both maximum and minimum, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used. The terms maximum and minimum are used through the standard, rationale and definitions with regard to voltage limits however it is common in industry to use the terms low, lowest, high and highest as synonyms for maximum and minimum and such usage is acceptable.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage Limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from maximum voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Part 3.5 requires that the SOL methodology define a method for determining common System Voltage Limits between RCs and TOPs. RC and TOPs may independently identify System Voltage Limits which if not coordinated could create reliability issues. An example could be where one TOP A chooses very wide System Voltage Limits on its equipment but TOP B could have much tighter System Voltage Limits even within the same substation. TOP A may operate equipment that are within its System Voltage Limits but cause an exceedance of TOP B's equipment. Coordinating the System Voltage Limits in these circumstances can prevent unnecessary exceedances of the System Voltage Limits.

Part 3.2 provides that in establishing System Voltage Limits, the SOL methodology shall respect any voltage-based Facility Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any voltage-based Facility Ratings for facilities that terminate at, or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that Undervoltage Load Shedding Programs (UVLS) should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL methodology shall ensure System Voltage Limits are not set at values less than UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

R4. Each Reliability Coordinator shall include in its SOL methodology the method for determining the stability limits to be used in operations. The method shall:

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5 applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area or other Reliability Coordinator Areas.

4.4. Describe how stability limits are determined, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are not allowed in the establishment of stability limits.

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic, and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of System damping.

Also included in Part 4.1 is language requiring the SOL methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations. Many stability tools will consider a subset of contingencies that are applicable to the area in study and are expected to produce more severe System impacts rather than every single potential contingency to set the limits conservatively while minimizing the time it takes to complete the solution, which is reflected in the phrase “applicable to the establishment of stability limits that are expected to produce more severe System impacts on its portion of the BES”. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, the SOL methodology could describe which TOP or RC has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance. Additionally, Requirement R4 Part 4.3 addresses when there is an impact to other Reliability Coordinator Areas.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL methodology. For example, the SOL methodology could state that stability limits will be determined for any combination of all facilities in and single facility out conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10 percent, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirement R3 Parts R3.1 and R3.4 into a single part while providing flexibility to the extent of the RC Area (including other RC Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require the modeling of the entire Reliability Coordinator Area to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) programs are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.7, UFLS programs or UVLS Programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS programs and UVLS Programs as measures of "last resort system preservation".

Requirement R5

R5. Each Reliability Coordinator shall identify in its SOL methodology the set of Contingency events for use in determining stability limits and the set of Contingency events for use in performing

Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The SOL methodology for each set shall:

5.1. Specify the following single Contingency events:

5.1.1. Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block in a monopolar or bipolar high voltage direct current system.

5.2. Specify additional single or multiple Contingency events or types of Contingency events, if any.

5.3. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-014-3, Requirement R7, to use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2 Part 2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3 Part 3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in FAC-011-3 Requirement R2 Part 2.2 and Requirement R3 Part 3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in the evaluation of post-Contingency state in OPAs and RTAs (thermal and voltage). The SOL methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that, at a minimum, must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events, such as inadvertent breaker operation and bus faults, may be considered if the probability of such an event is relevant. These Contingencies, if any, must be specified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Part 5.3 compliments the proposed Requirement R8 in FAC-014-3 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R5 establishes the contingency events for use in determining stability limits, in performing Operational Planning Analysis (OPAs), and in performing Real-Time Assessments (RTAs). The standard requirement is not meant to imply that all TOPs within the RC footprint must use that identical list spanning the entire RC region but may use a reduced list that at least covers the area they are responsible for the most limiting Contingencies.

Requirement R6

R6. Each Reliability Coordinator shall include the following performance framework in its SOL methodology to determine SOL exceedances when performing Real-time monitoring, Real-time Assessments, and Operational Planning Analyses:

6.1. System performance for no Contingencies demonstrates the following:

6.1.1. Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Predetermined stability limits are not exceeded.

6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

6.2. System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

6.2.1. Steady State post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Steady state post-Contingency voltages are within emergency System Voltage Limits.

6.2.3. The stability performance criteria defined in Reliability Coordinator's SOL methodology are met.

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1].

6.3. System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

6.4. In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

Rationale R6

Requirement R6 addresses BES performance criteria, which is addressed in the currently effective FAC-011-3 Requirement R2 Parts 2.1 and 2.2. The proposed requirement has some differences in the manner in which the performance criteria are addressed and in the level of detail reflected in the requirement when compared to the existing requirement. Those differences are discussed here.

Currently effective FAC-011-3 Requirement R2 states that the "*RC's SOL methodology shall include a requirement that SOLs provide BES performance consistent with the following.*" The subsequent subparts to FAC-011-3 Requirement R2 further describe pre-Contingency performance criteria (in Requirement R2 Part 2.1), the post-Contingency performance criteria (in Requirement R2 Part 2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in Requirement R2 indicates that the SOLs established in accordance with Requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of Requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011-3 Requirement R2 and its subparts.

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, the pre- and post-Contingency states are assessed on an ongoing basis as part of Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations through the application of the minimum performance criteria specified in FAC-011-4 requirement R6 and subparts. Under this construct, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the OPA and RTA for Facility Rating and System Voltage Limits. Stability limits are either established prior to the OPA/RTA or established and assessed during the OPA and RTA.

Requirement R6 works together with proposed TOP-001-5 Requirement R25 and IRO-008-3 R7 to support reliable operations for pre- and post-Contingency operating states. TOP-001 Requirement R25 states, *"Each Transmission Operator shall use the applicable RC's SOL methodology when*

determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis." IRO-008-3 Requirement R7 states*, "Each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."* The above noted requirements in TOP-001 and IRO-008 ensure that the performance framework identified in the SOL methodology is used to determine SOL exceedances consistently between the RC and its associated TOPs during Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis."

FAC-011-4 Requirement R6 Parts 6.1.1 and 6.1.2 are intended to prescribe the appropriate use of Emergency Ratings and Emergency System Voltage Limits when actual (or OPA no Contingency) flows or voltages exceed Normal Ratings or fall outside normal System Voltage Limits, respectively.

The language in Part 6.1.1 reflects the concepts in Figure 1 of the Project 2014-03 Whitepaper (NERC SOL Whitepaper) with regard to Facility Rating performance. Part 6.1.1 states, *"Steady state flow through Facilities are within applicable Emergency Ratings, provided that System adjustments to return the flow within its Normal Rating can be executed and completed within the specified time duration of those Emergency Ratings."* This is intended to allow, as an example, for the use of the 4-hour Emergency Rating and the 15-minute Emergency Rating consistent with the bullet descriptions in Figure 1. As is described in Figure 1, the use of the Emergency Ratings is governed by the amount of time it takes to execute the Operating Plan to mitigate the condition. The portion of Part 6.2.1 that states, *"Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating"* is intended to specifically address the operating state highlighted in yellow in Figure 1. In this operating state, the System Operator may have insufficient time to implement post-Contingency mitigation actions (i.e., actions that are taken after the Contingency event occurs); therefore, pre-Contingency mitigation actions consistent with the Operating Plan must be taken as soon as possible to reduce the calculated post-Contingency flow. However, as noted in the NERC SOL Whitepaper, pre-Contingency load shed may not be necessary or appropriate when assessment identifies that the impact is localized.

Requirement 6 applies only to those contingencies specified by the Reliability Coordinator for monitoring in the Transmission Operators RTA and OPA. If the Transmission Operators monitors additional contingencies beyond the subset required by the Reliability Coordinator, they are not required to meet the performance metrics in Requirement 6. As an example, if a TOP chooses to monitor loss of an entire substation as a contingency within their contingency analysis this section does not require that system performance following that event must meet these performance requirements. If the loss of a substation was not a defined contingency in the RC's SOL methodology, and no other defined contingency could cause loss of the entire substation, then the TOP could define what performance criteria, if any, to apply to this contingency. Said simply, R6 specifically applies only to the events and conditions described in R5.

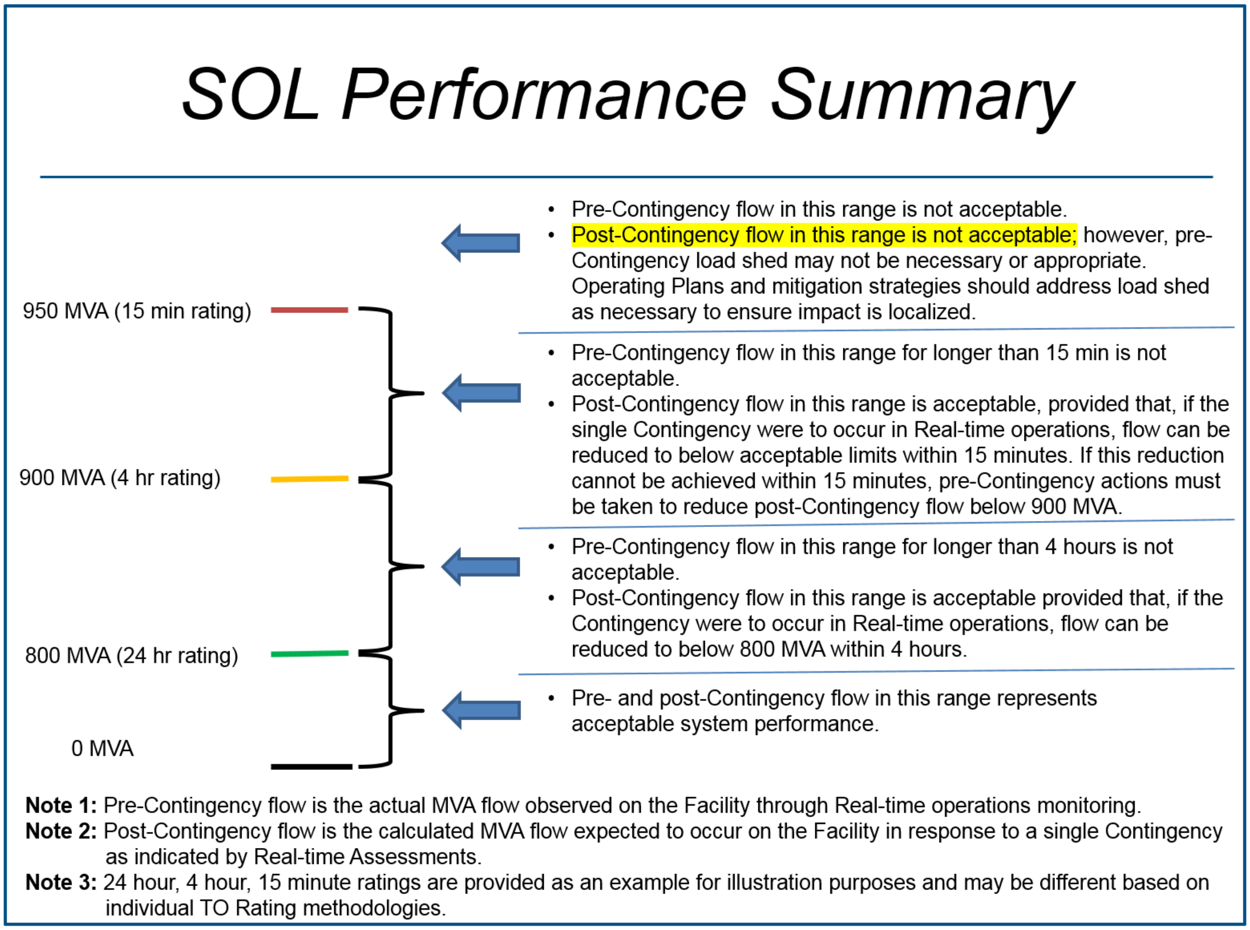

Figure 1 of the NERC SOL Whitepaper

The footnote referenced in Parts 6.1.4 and 6.2.3 states, "*Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.*" This helps to provide clarity that there are multiple methods to assessing if System performance demonstrates that Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur. Some entities determine stability limits across a variety of operating conditions and apply the appropriate limit to the operating condition in the OPA, RTA and Real time monitoring. Other entities may utilize tools that run at the time of the study to assess for acceptable performance or determine stability limits at the time of the OPA or RTA. Others may yet utilize other offline analysis techniques.

Part 6.3 recognizes the potential for regional differences and is intended to describe the minimum performance criteria for Contingency events that are more severe than the single Contingency events listed in Requirement R5 Part 5.1.1 for OPAs and RTAs (i.e., Contingencies identified in Part 5.2). Per Part 6.3, if any of these more severe Contingency events were to occur, at a minimum the System is expected to remain stable, there should be no Cascading, and there should be no uncontrolled separation that adversely impact the reliability of the Bulk Electric System.

Part 6.4 maintains the concept identified in FAC-011-3 Requirement R2 Part 2.3.2 and intent of FERC Order No. 705, where FERC determined that load shedding shall only be utilized by system operators as a measure of last resort to prevent cascading failures. Part 6.4 clarifies that load shedding as a remedy in the operating plan should only be allowed by the RC's methodology after other options are exercised without regard for financial impact. The term "planned manual load shedding" refers to the inclusion of planned post-Contingency shedding of load either manually or by automated methods in an Operating Plan. This Operation Plan is developed in response to SOL exceedances identified in its Operating Planning Analysis including for contingencies identified in Requirement R5 against the transmission system under study and would apply to the Operational Planning Analysis. While those plans guide an operator's response to an event in Real-time monitoring or a Real-time Assessment, Part 6.4 would not directly apply to the actions taken by the operator in real time.

For clarity, the following examples of pre- or post-Contingency actions are provided to expand on the term "all other available System adjustments" that should have been made prior to planning to utilize load shedding:

- Generation commitment and re-dispatch regardless of economic cost, when the generation has a significant impact on the SOL exceedance.
- Curtailment and adjustment of Interchange regardless of economic cost, when the Curtailment or adjustment of Interchange has a significant impact on the SOL exceedance.
- Transmission re-configuration (only if studies shows that the re-configuration does not put more load at risk or create other unacceptable system performance)

Transmission re-configuration that does place more load at risk or create other unacceptable system performance issues is not required to be used prior to planned manual load shedding. As an example the reconfiguration of a looped network into a series of radial connections to avoid planned post contingency manual load shedding could be a re-configuration that puts more load at risk. In those circumstances the TOP and RC must select that option that best fits their operating conditions and Requirement R6 Part 6.4 is not intended to prescribe one approach over the other. Planned "manual" load shedding would be load shed plans, as part of an Operating Plan, and is load that would be shed as part of an Operator Instruction or taking action to shed the load in Real-time. Reconfiguration of a system in Real-time to avoid or lessen the amount of planned manual load shed or reconfiguration of a system in Real-time that creates additional "consequential" load loss is not part of "planned manual load shedding". Furthermore, the "all other available System adjustments" would apply only to those adjustments studied by the TOP or RC at the time of the Operating Planning Analysis and not to system adjustments that might be found during a post event review days or weeks later. Part 6.4 is an addition to the RC's SOL methodology and the RC can provide additional clarity as appropriate to their circumstances.

Planned manual load shedding in the context of Requirement R6 Part 6.4 is specific to what could be considered "firm" load, and would not include non-firm load, interruptible load, or any other load that has an arrangement that allows the load to be shed or interrupted when needed.

Requirement R7

R7. Each Reliability Coordinator shall include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, the timeframe that communication must occur. The approach shall include:

7.1. A requirement that the following SOL exceedances will always be communicated, within a timeframe identified by the Reliability Coordinator.

7.1.1. IROL exceedances

7.1.2. SOL exceedances of stability limits;

7.1.3. Post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation

7.1.4. Pre-contingency SOL exceedances of Facility Ratings

7.1.5. Pre-contingency SOL exceedances of normal minimum System Voltage Limits.

7.2. A requirement that the following SOL exceedances must be communicated, if not resolved within 30 minutes, within a timeframe identified by the Reliability Coordinator.

7.2.1. Post-contingency SOL exceedances of Facility Ratings and emergency System Voltage limits

7.2.2. Pre-contingency SOL exceedances of normal maximum System Voltage Limits.

Rationale R7

The changes in proposed FAC-011-4 help to provide clarity by requiring a performance framework for determining SOL exceedances in the RC's SOL methodology. This provides better uniformity in determining what is and isn't an SOL exceedance. This clarity may increase the instances of what is determined to be an SOL exceedance and thus increase the instances of communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirements R5 and R6) which states, "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.*"

Concerns were raised as to the effect on Real-time System Operators being required to communicate every SOL exceedance, especially those which were considered short duration SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 Requirement R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

Part 7.1 requires that the risk based approach require that "IROL exceedances, SOL exceedances of stability limits, post-contingency SOL exceedances that are identified to have a validated risk of instability, Cascading Outages, and uncontrolled separation and pre-contingency SOL exceedances of Facility Ratings and pre-contingency Minimum System Voltage Limits will always be communicated". While typically less frequent, these subset of SOL exceedances were determined to be of a higher risk and must always be communicated between TOP's and RC's. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Part 7.2 requires that the risk based approach require that "Post-contingency SOL exceedances of Facility Ratings and System Voltage limits and pre-contingency Normal Maximum System Voltage Limits must be communicated, if not resolved, within a timeframe identified by the RC which cannot exceed 30 minutes". While typically more frequent, these subset of SOL exceedances were determined to be of a lower risk allow the RC to identify a timeframe which cannot exceed 30 minutes whereby if the SOL exceedance is mitigated (no longer an SOL exceedance) within the identified timeframe (e.g. 15min, 30 min, etc.), the SOL exceedance would not be required to be communicated to the TOP or RC. The RC must identify the priority of communications during circumstances where multiple SOL exceedances may exist.

Nothing prohibits an RC from requiring all or an additional subset of SOL exceedances than what is identified in Part 7.1 from being communicated. Nothing prohibits a Real-time System Operator from communicating beyond what is required or in line with other good utility practice (e.g. troubleshooting or communicating). These provisions are meant to ensure that a risk based approach can be applied to prevent low risk or after the fact communications from distracting System Operators from other higher priority tasks.

This proposed requirement is coordinated with proposed changes to TOP-001-5 Requirement R15 which states "*Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology.***" and with proposed IRO-008-3 Requirements R5 and R6 which state, **"***Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded* ***in accordance with its Reliability Coordinator's SOL methodology****."* and **"***Each Reliability Coordinator shall notify****, in accordance with SOL methodology****, impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.***",** respectfully.

Requirement R8

R8. Each Reliability Coordinator shall include in its SOL methodology:

8.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

8.2. Criteria for determining when exceeding a SOL qualifies as exceeding an IROL and criteria for developing any associated IROL T_v.

Rationale R8

The two IROL related requirements in FAC-011-3 were preserved under Requirement R8. Part 8.2 utilizes terminology consistent with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards by replacing “violating” with “exceeding”. It also inserts “exceeding” before the IROL to better harmonize with proposed FAC-011-4, and the IRO/TOP NERC Reliability Standards.

Requirement R9

R9. Each Reliability Coordinator shall provide its SOL methodology to:

- **9.1.** Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.
- **9.2.** Each of the following entities prior to the effective date of the SOL methodology:
  - **9.2.1.** Each adjacent Reliability Coordinator within the same Interconnection;
  - **9.2.2.** Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;
  - **9.2.3.** Each Transmission Operator within its Reliability Coordinator Area; and
  - **9.2.4.** Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

Rationale R9

Requirement R9 preserves the reliability objective of providing the SOL methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL methodology. Additionally, requirement 9 Part 9.2 enforces provision to those entities that would require notification of an update or change to the RC’s SOL methodology.

In Requirement R9 Part 9.2.2, Planning Coordinator (PC), not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R9 Part 9.2.2 also uses “responsible for planning” instead of “models any portion of” to distinguish those PCs and Transmission Planners (TPs) who have a reliability-related need from a PC/TP who simply has acquired a model that contains a portion of the RC Area, but does not plan for that area. Requirement R9 Part 9.2.4 differs from Requirement R9 Parts 9.2.1 through 9.2.3 in that it mandates provision of the SOL methodology to non-adjacent RCs that have specifically requested to receive updates, and indicated they had a reliability-related need.

Technical Rationale for Reliability Standard FAC-014-3

April 2021

FAC-014-3 – Establish and Communicate System Operating Limit

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs for its portion of the Reliability Coordinator Area, and that these SOLs must be established in accordance with the RC's SOL methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under Requirement R2) to the RC. The TOP should refer to the RC's documented data specification necessary for the RC to perform Operational Planning Analyses, Real-time monitoring and Real-time assessments under IRO-010-2 for any guidance or requirements regarding the provision of SOLs from the TOP. For example, the RC may wish to specify the periodicity and format in which the data should be communicated. The RC may choose to also provide this or any additional guidance within its SOL methodology. If no such information is given, the TOP may provide SOLs as per other terms agreed upon with the RC.

This requirement was previously covered under FAC-014-2 Requirement R5.2 but was moved to a more logical position in the standard, immediately following Requirement R2 for establishing SOLs.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2. However, the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA), Real-time Assessment (RTA) and Real-time monitoring. In such instances, the timing requirements should be coordinated between the data specification document and the RC's SOL methodology.

Requirement R3 sets a common expectation across industry of the minimum actions any TOP must take when communicating SOLs to their RC. It's important for this requirement to remain within FAC-014-3 to ensure SOLs are communicated from the TOP to the RC in case IRO-010-2 is modified or removed in future revisions to the standards.

Requirement R4

Each Reliability Coordinator shall establish stability limits when an identified instability impacts adjacent Reliability Coordinator Areas or more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits when the limit impacts more than one TOP in its RC Area. This ensures that the RC, who has wide-area responsibility, will establish such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to establish stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area). The requirement establishes the end condition, which is the RC being responsible for establishing a stability limit that impacts more than one TOP regardless of whether that stability limit was originally calculated by the RC or one of the impacted TOPs. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s)or TOP(s) appropriately in accordance with other NERC standards requiring the communication of SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5, IRO-014-3 Requirements R1.4 and R1.5 and FAC-014-3 Requirement R5.3). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

RCs who have asynchronous connections should consider the impact of all possible transfer levels across those connections including when those connections are not available if lost by contingency or forced outage.

Requirement R5

Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1 Each Planning Coordinator and each Transmission Planner within its Reliability Coordinator Area, the SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

5.2 Each impacted Planning Coordinator and each impacted Transmission Planner within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months: *[Time Horizon: Operations Planning]*

5.2.1 The value of the stability limit or IROL;

5.2.2 Identification of the Facilities that are critical to the derivation of the stability limit or the IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated critical Contingency(ies);

5.2.5 A description of system conditions associated with the stability limit or IROL; and

5.2.6 The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3 Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.4 Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.6 for each established stability limit and each established IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.5 Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. *[Time Horizon: Operations Planning]*

5.6 Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months. *[Time Horizon: Operations Planning]*

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs), Transmission Planners (TPs) and Transmission Operators (TOPs). This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause for RCs to provide SOLs when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-2) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed in IRO-014-2. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the impacted PCs and TPs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC and the TP the relevant information necessary for their annual assessments; however nothing precludes the PC and TP from requesting this information more frequently. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs and TPs with additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

In addition, Requirement R5 Part 5.2.5 requires the RC to provide the impacted PCs and TPs with unique system conditions associated with a particular stability limit or IROL as opposed to generic study conditions directed at covering all (or a group of) stability limits which may be included in the RC's SOL methodology as required by, Requirement R4 Part 4.4 in FAC-011-4. For example, where the RC's SOL methodology may describe that stability limits must be verified for "summer peak", "winter peak", "minimum demand" and "shoulder periods", the information provided under , Requirement R5 Part 5.2.5 would identify whether the particular stability limit was present in all or just one of those conditions.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA. In the case where the stability limit impacts an adjacent RC or multiple TOPs which may or may not be in the same RC area, the RC establishing the stability limit shall use its own methodology and communicate the limit to the adjacent RC(s) or TOP(s) appropriately in accordance with other NERC standards requiring the communication SOL and IROL related information (i.e. currently in effect IRO-008-2 Requirement R5 and IRO-014-Requirements 1.4 and 1.5)). Should there be a difference in limits established by each of the adjacent RCs or multiple TOPs; the more conservative of the two limits should be the one used in Operations in accordance with IRO-009-2 Requirement R3 or TOP-001-4 Requirement R18 respectively.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. For example, in deriving a new SOL that may impact adjacent TOPs, a TOP may need more information from the RC on related SOLs in other TOP areas within the region that could impact their derivation. Requirement R5, Parts 5.3 through 5.5, require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Finally, Requirement R5, part 5.6, requires that the RC must provide each impacted Generation Owner or Transmission Owner within its Reliability Coordinator area with a list of Facilities that they can use to satisfy the criteria in Attachment 1 part 2.6 in CIP-002 and 4.1.1.3 in CIP-014. Of the three possible entities, RC, TP and PC listed in CIP-002 and CIP-014 that could deliver this information to the TOs and GOs, the RC is ultimately responsible given they're required to establish IROLs. Thus, the requirement for provision of the list of Facilities identified as critical to the derivation of an IROL and its associated critical contingencies should rest with the RC. The SDT also felt that some known periodicity of information provision, per this requirement, seemed appropriate. After industry comment, an annual periodicity was chosen. This timeframe should allow sufficient analysis to document IROLs that will persist, and need monitoring by the RC and any necessary action by asset owners, per the CIP standards. Those IROL like conditions which may manifest in real time, due to forced outages are not appropriate for consideration until reviewed by the RC to determine if they are to be established as an IROL to prevent the condition from reoccurring, and warrant reporting per the standard.

Requirement R6

Each Planning Coordinator and each Transmission Planner shall implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its Reliability Coordinator's SOL methodology.

- The Planning Coordinator may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Transmission Planner, Transmission Operator and Reliability Coordinator.
- The Transmission Planner may use less limiting Facility Ratings, System steady-state voltage limits and stability criteria if it provides a technical rationale to each affected Planning Coordinator, Transmission Operator and Reliability Coordinator.

Rationale R6

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R6 was drafted to ensure the appropriate use of applicable Facility Ratings, System steady-state voltage limits, and stability performance criteria in operating and planning models. Analysis of these models determine System needs, potential future transmission expansion, and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of Facilities when they are placed in service.

Requirement R6 provides a mechanism for the coordination of Facility Ratings, System steady-state voltage limits, and stability performance criteria in planning models to those established in accordance with the RC's SOL methodology. Since the analysis of planning models determines what Facilities are constructed or modified, the application of Facility Ratings, System steady-state voltage limits, and stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL methodology. Otherwise, operators could be unduly limited by constraints that were not identified in preceding planning studies.

The Near-Term Transmission Planning Horizon is specified because assumptions regarding the topology of the transmission system, forecast load and generation, etc. are more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be in the implementation phase or finalized in this period.

Facility Ratings:
Reliability Standard MOD-032 requires the modeling data in a PC area be coordinated between the PC and applicable TP. It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means for consistency between the PC and TP in ensuring Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL methodology. This is important because Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The intent of Requirement R6 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008, nor allow the PCs nor TPs to revise those limits. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC and TP to use the owner-provided Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL methodology. This is not intended to imply the RC has authority over the PCs and TPs planning a portion of the RC area in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

The SDT recognizes there are instances where it may be appropriate for planning models to have less limiting Facility Ratings than those established in accordance with the RC's SOL methodology. As such, Requirement R6 explicitly allows for exceptions when a technical rationale is provided to the appropriate entities in accordance with the requirement. The obvious example for such an exception is a facility where the PC / TP has assumed an upgrade which increases the Facility Rating (typically, the thermal limit) of the equipment in question.

Furthermore, it is the SDT's intent to clarify that Facility Ratings that result from variables such as the implementation of future Corrective Action Plans, or the use of ambient temperature assumptions in seasonal planning models that differ from those ambient weather assumptions used in operational analyses and monitoring in real time, may be used. Although they may be less limiting than those in the RC's SOL methodology in certain instances, it is understood that seasonal assumptions and capacity increases due to upgrade are appropriately included in future planning models. These provisions should be included in the documented technical rationale provided to the appropriate entities in accordance with the requirement.

System Steady-State Voltage Limits:
Regarding voltage performance criteria, the intent of this requirement is to supplement Requirement R5 of TPL-001-4 which states, "Each TP and PC shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R5, PCs and TPs are required to implement the process described in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Stability Performance Criteria:
Regarding stability performance criteria, the intent of this requirement is to supplement the performance of stability analysis by the PC and TP per TPL-001. When PCs and TPs perform the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-014-3 Requirement R6. Per FAC-014-3, R6, the PC and TP are required to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL methodology. This does not give the RC authority over the PCs and TPs, responsible for planning a portion of the RC area, in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R7

Each Planning Coordinator and each Transmission Planner shall annually communicate the following information for Corrective Action Plans developed to address any instability identified in its Planning

Assessment of the Near-Term Transmission Planning Horizon to each impacted Transmission Operator and Reliability Coordinator. This communication shall include:

7.1 The Corrective Action Plan developed to mitigate the identified instability, including any automatic control or operator-assisted actions (such as Remedial Action Schemes, under voltage load shedding, or any Operating Procedures);

7.2 The type of instability addressed by the Corrective Action Plan (e.g. steady-state and/or transient voltage instability, angular instability including generating unit loss of synchronism and/or unacceptable damping);

7.3 The associated stability criteria violation requiring the Corrective Action Plan (e.g. violation of transient voltage response criteria or damping rate criteria);

7.4 The planning event Contingency(ies) associated with the identified instability requiring the Corrective Action Plan;

7.5 The System conditions and Facilities associated with the identified instability requiring the Corrective Action Plan.

Rationale R7

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment and the associated Corrective Action Plan, do not provide for the level of detail prescribed in FAC-014-3 Requirement R7. Therefore, this requirement was drafted to ensure the appropriate details regarding any potential instability identified in the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and TOPs.

The information itemized in FAC-014-3 Requirement R7 is a key consideration for RCs and TOPs in the establishment of SOLs. For example, a study might indicate that System instability was avoided through the implementation of an operational measure, or Remedial Action Scheme (RAS). In this example, if the operational measure or RAS were not employed, the study would indicate instability in response to the associated Contingency. This information is critical for operator awareness of any automatic or manual actions that are required to prevent instability. Without this information, operators may be unaware of these risks and the measures required to address them. Existing FAC-014-2, Requirement R6 requires similar, though less detailed, information is shared by the planning with the RC. The SDT believes FAC-014-3, Requirement R7, improves upon this requirement and provides added clear and concise information to its impacted RCs and TOPs.

In addition, FAC-014-3 Requirement R7 Part 7.4 is useful information which supports FAC-014-3 Requirement R8. The information from Requirement R8 supports a number of other standards which require the PC and TP to provide information regarding instability, Cascading, and uncontrolled separation that adversely impacts the reliability of the BES to the TO and GO.

Requirement R8

Each Planning Coordinator and each Transmission Planner shall annually communicate to each impacted Transmission Owner and Generation Owner a list of their Facilities that comprise the planning event Contingency(ies) that would cause instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES as identified in its Planning Assessment of the Near-Term Transmission Planning Horizon.

Rationale R8

This requirement was drafted to ensure the appropriate details (i.e. Facilities) regarding potential instability, Cascading, or uncontrolled separation identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted Transmission and Generation Owners. Impacted Transmission and Generation Owners consist of those entities who have facilities requiring notification and **does not** imply that all Transmission and Generation Owners need notification of whether they have facilities requiring notification or not. This is necessary to ensure Facility owners receive this input to identify the Facilities that, as required by other Reliability Standards, require some level of protection, hardening, or increased vegetative management provisions. This requirement further supports the SDT’s proposed changes to other Reliability Standards being updated to account for the retirement of FAC-010.

Furthermore, this requirement addresses the FERC Order No. 777 directive identified in the Standard Authorization Request (SAR) for project 2015-09, requesting a requirement be added for the communication of IROL information to Transmission Owners. This requirement, coupled with Requirement 5.6, provides annual notifications to Facility owners from both operating and planning entities, whereas no such timely notification requirements exist in the standards today.

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Technical Rationale for Reliability Standard IRO-008-3

April 2021

IRO-008-3 – Reliability Coordinator Operational Analyses and Real-Time Assessments

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board of Trustees approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

Rationale for R2 and R3:
Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

Rationale for R5 and R6:
In Requirements R5 and R6 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications. The use of the terminology “in accordance with its SOL methodology, aligns the notification requirements with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other

real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard.

Rationale for R7:

Requirement R7 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

Technical Rationale for Reliability Standard TOP-001-6

April 2021

TOP-001-6 – Transmission Operations

Rationale

Rationale text from the development of TOP-001-3 in Project 2014-03 and TOP-001-4 in Project 2016-01 follows. Additional information can be found on the Project 2014-03 and Project 2016-01 pages.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

The revised requirement addresses directives for Transmission Operator (TOP) monitoring of some non-Bulk Electric System (BES) facilities as necessary for determining System Operating Limit (SOL) exceedances (FERC Order No. 817 Para 35-36). The proposed requirement corresponds with approved IRO-002-4 Requirement R4 (proposed IRO-002-5 Requirement R5), which specifies the Reliability Coordinator's (RC) monitoring responsibilities for determining SOL exceedances.

The intent of the requirement is to ensure that all facilities (i.e., BES and non-BES) that can adversely impact reliability of the BES are monitored. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. The facilities that are necessary for determining SOL exceedances should be either designated as part of the BES, or otherwise be incorporated into monitoring when identified by planning and operating studies such as the Operational Planning Analysis (OPA) required by TOP-002-4 Requirement R1 and IRO-008-2 Requirement R1. The SDT recognizes that not all non-BES facilities that a TOP considers necessary for its monitoring needs will need to be included in the BES.

The non-BES facilities that the TOP is required to monitor are only those that are necessary for the TOP to determine SOL exceedances within its Transmission Operator Area. TOPs perform various analyses and

studies as part of their functional obligations that could lead to identification of non-BES facilities that should be monitored for determining SOL exceedances. Examples include:

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and
- Analysis which may be specified in the RC's outage coordination process that leads the TOP to identify a non-BES facility that should be temporarily monitored for determining SOL exceedances.

TOP-003-3 Requirement R1 specifies that the TOP shall develop a data specification which includes data and information needed by the TOP to support its OPAs, Real-time monitoring, and RTAs. This includes non-BES data and external network data as deemed necessary by the TOP.

The format of the proposed requirement has been changed from the approved standard to more clearly indicate which monitoring activities are required to be performed.

Rationale for Requirement R13:
The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:
The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

FAC-011-4 R6 clarifies when an SOL exceedance is occurring and as such likely increases the number of SOL exceedances for some TOPs. This increased number of SOL exceedances could create an administrative burden on System Operators for entities that rely on operator logs as the primary form of evidence for compliance. This would be an unintended consequence of interaction between the new FAC-011-4 R6 and TOP-001-4 Requirement 14, which states, “Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.” This is because TOP-001-4 Requirement 14 treats all SOL exceedances equally and does not differentiate among them based on duration or risk to the BES.

Concerns were raised by drafting team members and observers as to the effect on Real-Time System Operators being required to log initiation of the Operating Plan for every SOL exceedance per TOP-001-4 R14, especially those which were considered short duration, low risk SOL exceedances that were actually successfully mitigated within a short-term time frame. This could distract System Operators to focus on compliance documentation during times when they should be fully committed to implementing the Operating Plan and mitigating the SOL exceedance.

The revised TOP-001-6 M14 addresses this concern by identifying examples of “other evidence” that can be utilized to support compliance which require less human intervention for capturing. Examples allowing TOPs to use other types of evidence such as system logs/records showing the SOL exceedance successfully mitigated in conjunction with Operating Plans is important because it clarifies that validation of successful SOL mitigation is the primary interest and focus of evidence. Successful SOL mitigation coupled with Operating Plans that have been prepared for utilization in the event of an SOL exceedance can demonstrate that the TOP initiated and implemented its Operating Plan. For example, providing outputs of State Estimator and/or Real-Time Contingency Analysis (with start time and end time of SOL exceedances) in conjunction with Operating Plans that outline roles and responsibilities between TOP and its RC in eliminating SOL exceedances, would document resolution of the SOL exceedance as well as the Operating Plan in use for the resolution. These should be sufficient evidence for Requirement R14 while reducing or eliminating the administrative burden on System Operators to manually generate compliance evidence via logging or recording actions.

These Operating Plans may be strengthened with clarifying information such as automatically switched or scheduled switching operating strategies/processes that describe how automatic control actions correct SOL exceedances, which can prevent unnecessary collection of evidence. Use of operating policies as a part of Operating Plan may include specific control actions (such as taking a transmission line out of service or disconnecting a generator for a low risk high voltage SOL exceedance) on post-contingent basis, and may be utilized if it was included into operating protocols and confirmed in real-time. Other records, such as binding constraint logs, could document the actions taken to alleviate certain thermal SOL exceedances through the role of redispatch algorithms that generate revised dispatch setpoints for generators to alleviate the constraint.

Finally, further evidence may include some of the operating protocols shared between a TOP and RC as part of the Operating Plan; they may support instances where the TOP and RC agree to each take certain predetermined actions and or share information. For example, if an RC had to initiate manual redispatch with a Generator Operator when a TOP initiated binding constraint was insufficient (e.g. not fast enough), the TOP may utilize RC-provided logs as evidence of compliance if the RC and TOP have agreed to share such information. Additionally, use of these joint operating protocols as evidence recognizes situations

and operating conditions when the RC initiates and implements an Operating Plan on behalf of TOP, per these joint operating protocols. In these situations, pre-specified actions taken by the TOP and RC and agreed upon in their joint operating protocols could allow the RC's binding constraint logs to be used by the TOP as evidence of compliance.

Rationale for Requirement R15:
Clarity of what is determined to be an SOL exceedance in new revision FAC-011-4 may increase, in some instances, the number of SOL exceedances and thus the communications that are required consistent with TOP-001-4 Requirement R15 (as well as IRO-008-2 Requirement R5 and R6) which states, "Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded."

Concerns were raised as to the effect on System Operators being required to communicate every SOL exceedance, especially those which were considered short duration, low risk, SOL exceedances (e.g. less than 15 min, 30 min). This could be a significant increase for entities that historically performed RTAs more frequent than the required 30 minutes. Proposed FAC-011-4 R7 addresses this concern by requiring the RC to include in its SOL methodology a risk-based approach for determining how SOL exceedances identified as part of Real-time monitoring and Real-time Assessments must be communicated and if so, with what priority. This will ensure consistency within an RC's area between the RC and its TOPs.

The use of the terminology "in accordance with its SOL methodology, aligns the notification requirements of TOP-001-5 R15 with the communication requirements identified in FAC-011-4 Requirement R7 around communication of SOL exceedances. For example, the SOL methodology could state that an RC and TOP sharing with each other real time monitoring and RTCA output information could provide clear communication and indications of when SOL exceedances appear and are mitigated in real time, meeting the requirements of the standard. This communication could range from simply RC and TOP sharing via ICCP output from the real time monitoring and RTCA output to operator to operator communications.

Rationale for Requirements R16 and R17:
In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:
Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20 (R19, R20, R22, and R23 in TOP-001-4):
[Note: Requirement R19 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements.]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the TOP's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R21:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component (e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for Requirements R22 and R23:
[Note: Requirement R22 proposed for retirement under Project 2018-03 Standards Efficiency Review Retirements]

The proposed changes address directives for redundancy and diverse routing of data exchange capabilities (FERC Order No. 817 Para 47).

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g., switches, routers, servers, power supplies, and network cabling and communication

paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Balancing Authority's (BA) primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange infrastructure from halting the flow of Real-time data. Requirement R23 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the BA's primary Control Center.

The reliability objective of redundancy is to provide for continued data exchange functionality during outages, maintenance, or testing of data exchange infrastructure. For periods of planned or unplanned outages of individual data exchange components, the proposed requirements do not require additional redundant data exchange infrastructure components solely to provide for redundancy.

Infrastructure that is not within the BA's primary Control Center is not addressed by the proposed requirement.

Rationale for Requirement R24:
The proposed requirement addresses directives for testing of data exchange capabilities used in primary Control Centers (FERC Order No. 817 Para 51).

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component(e.g., switches, routers, servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data). An entity's testing practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

Rationale for R25:
Requirement R25 was added to align the Real-time Assessments, Real-time Monitoring, and Operational Planning Analysis activities with the RC's SOL methodology. This will ensure that methods and frameworks that surround what is required in the SOL methodology are utilized during these activities (e.g. contingencies utilized, stability criteria, performance framework, etc.) in determining SOL exceedances.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the standard drafting team's (SDT) intent with regard to the SOL concept, and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:

The approved definition of SOL as defined in the NERC Glossary of Terms is:

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- *Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)*
- *Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)*
- *Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)*
- *System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)*

The proposed revised definition of SOL is:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

The concept of SOL determination is not complete without looking at the associated NERC FAC standards approved FAC-008-3, proposed FAC-011-4, and proposed FAC-014-3 and related TOP and IRO standards (proposed TOP-001-6 and IRO-008-3):

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Ratings methodology and to establish

Facility Ratings consistent with that methodology that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed are required to include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal Rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Emergency Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of proposed FAC-011-4, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Proposed FAC-011-4 contains requirements that addresses each type of SOL: Facility Ratings, System Voltage Limits, and stability limits:

   a. Requirement R2 requires that the Reliability Coordinator's SOL methodology include the method for Transmission Operators to determine which owner-provided Facility Ratings (provided via FAC-008-3) are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings.

   b. Requirement R3 requires that the Reliability Coordinator's SOL methodology include the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The subparts of requirement R3 contain several associated requirements.

   c. Requirement R4 requires that the Reliability Coordinator's SOL methodology include the method for determining the stability limits to be used in operations. The subparts of requirement R4 contain several associated requirements.

3. Proposed FAC-011-4 requirement R6 contains the minimum framework for SOL exceedance determination to be used in the TOP and IRO standards. Specifically, requirement R6 requires the Reliability Coordinator's SOL methodology to include, at a minimum, the following Bulk Electric System performance framework:

   a. Part 6.1: System performance for no Contingencies demonstrates the following:

      Part 6.1.1.~~:~~ Steady state flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

      Part 6.1.2. Steady state voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

      Part 6.1.3. Predetermined stability limits are not exceeded.

Part 6.1.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.[1]

i. ~~Part 6.1.3:~~

~~b.~~a. Part 6.2: System performance for the single Contingencies listed in Part 5.1 demonstrates the following:

i. Part 6.2.1: Steady ~~S~~state post-Contingency flow through Facilities within applicable Emergency Ratings. Steady state post-Contingency flow through a Facility must not be above the Facility's highest Emergency Rating.

ii. Part 6.2.2: Steady state post-Contingency voltages are within emergency System Voltage Limits.

iii. Part 6.2.3: The stability performance criteria defined in the Reliability Coordinator's SOL methodology are met[1].

iv. Part 6.2.4. Instability, Cascading or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur[1]

~~c.~~b. Part 6.3: System performance for applicable Contingencies identified in Part 5.2 demonstrates that: instability, Cascading, or uncontrolled separation that adversely impact the reliability of the Bulk Electric System does not occur.

~~d.~~c. Part 6.4: In determining the System's response to any Contingency identified in Requirement R5, planned manual load shedding is acceptable only after all other available System adjustments have been made.

4. Proposed FAC-014-3, Requirement R2 requires that Transmission Operators ~~to~~ establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL methodology.
5. Proposed TOP-001-6, Requirement R25 and IRO-008-3, Requirement R7 require Transmission Operators and Reliability Coordinators, respectively, to use the Reliability Coordinator's SOL methodology when performing Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analyses to determine SOL exceedances. The SOL ~~exceedance framework~~exceedance framework is included in the SOL methodology via the proposed FAC-011-4 requirement R6 (above).
6. The requirements within proposed FAC-011-4, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all Facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into operations studies.

Some have interpreted the language in previous versions of FAC-011 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the

[1] Stability evaluations and assessments of instability, Cascading, and uncontrolled separation can be performed using real-time stability assessments, predetermined stability limits or other offline analysis techniques.

criteria specified in FAC-011, with the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in FAC-011 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within FAC-011, which is both:

1. To know the Facility Ratings, voltage limits, transient ~~S~~stability criteria, and voltage Stability criteria, and
2. To ensure that they are all observed in assessments of both the pre- and post-Contingency state when performing Operational Planning Analyses (OPA), Real-time Assessments (RTA), and Real-time monitoring.

It is important to understand the intent behind the language "the pre- and post-contingency state." The pre-Contingency state is synonymous with the actual or initial state of the system. For example, for Real-time monitoring and Real-time Assessments, the pre-Contingency state refers to actual flows and voltages on the system as indicated by SCADA systems or state estimators at the time the assessment or monitoring occurs. For OPAs, the pre-Contingency state refers to the base case flows and voltages in the system models that are observed prior to simulating any Contingencies.

The post-Contingency state is a calculation or simulation of the expected state of the system if a Contingency were to occur. The post-Contingency state can be determined, or calculated, by analysis processes or tools such as Real-time Contingency Analysis (RTCA). Such tools calculate the flows and voltages on the system that are expected to occur based on simulated Contingencies. It is important to understand that when this document refers to the post-Contingency state or post-Contingency flows or voltages, it is referring to calculations based on analysis processes or tools. It is not referring to the state of the system after a Contingency event actually occurs. When a Contingency event actually occurs in Real-time operations, the system is now in a new state. The former post-Contingency state is now the new pre-Contingency state, and new RTAs then need to be executed to determine the new post-Contingency state based on these new conditions.

A primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. In Real-time operations, any of these types of limits can be the most restrictive limit at any point in time in the pre- or post-Contingency state. For example, if an area or Facility of the BES is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of thermal Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, a primary focus of System Operators is to ensure reliable operations with regard to Facility Ratings, System

Voltage Limits, and transient and voltage stability criteria for the pre- and post-Contingency state. How an entity accomplishes this objective can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator (TOP) may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective. To illustrate, a TOP may restrict flow over a major interface to a pre-determined value as a means by which to prevent a Contingency from causing a Facility to exceed its Emergency Rating. In this scenario, the restriction of flow on this interface can be considered as the Operating Plan to prevent exceeding a Facility Rating. Similarly, a TOP might restrict flow on a Facility to ensure that voltages at a bus remain within System Voltage Limits. In this scenario the flow restriction can be considered as the Operating Plan employed to prevent exceeding a System Voltage Limit.

In order to ensure reliable operations, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.

2. **System Voltage Limits:**
   In the pre-Contingency and post-Contingency state, operate within normal System Voltage Limits and emergency System Voltage Limits, as applicable, within their associated time parameters.

3. **Stability Limits:**
   Stability limits are typically established to address stability phenomena in the transient or the steady-state timeframes. Stability limits are unique in that they typically are established to prevent a Contingency or a specific set of Contingencies from resulting in the particular type of instability identified in studies. Proposed FAC-011-4 requirement R4, part 4.1 requires the RC's SOL methodology to include and specify stability performance criteria for steady-state voltage stability, transient voltage response, ~~unit~~ angular stability, and System damping. Part 4.2 requires stability limits to be established to meet these prescribed stability performance criteria. For example, a study might indicate that a three-phase fault at a particular location results in exceeding the transient damping criteria threshold. A transient stability limit would be established to prevent a fault at that location from the unacceptable damping.

   Transient Stability Limits:
   Transmission Operators establish transient ~~s~~Stability limits to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or loading level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

   Voltage Stability Limits:
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the

maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:
The combination of requirements contained within the proposed FAC and the proposed and approved TOP and IRO standards, as well as the use of defined terms contained within those standards such as OPA, RTA, and Operating Plans when executed properly result in maintaining reliable BES performance.

Specifically,

1. FAC standards require clear determination of Facility Ratings (approved FAC-008-3) and describe a performance framework for the pre- and post-Contingency state (proposed FAC-011-4 requirement R6) for SOL exceedance determinations.
2. TOP-001-~~3~~6, Requirement R13 requires that each Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. TOP-001-6, Requirement R25 requires that each Transmission Operator shall use the applicable Reliability Coordinator's SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.
4. TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
5. TOP-001-~~3~~6, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.
6. IRO-008-3, Requirement R7 requires that each Reliability Coordinator shall use its SOL methodology when determining SOL exceedances for Real-time Assessments, Real-time ~~M~~monitoring, and Operational Planning Analysis.

Facility Rating Exceedance

Facility Ratings include Normal Ratings and one or more Emergency Ratings. While Normal Ratings represent loading values that the facility can support or withstand through the daily demand cycles without loss of equipment life, Emergency Ratings allow for higher facility loading that can occur for a finite period of time and assumes acceptable loss of equipment life or other acceptable physical or safety limitations. Acceptable Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. The System Operator's goal with respect to Facility Rating exceedances is to take action as necessary, making use of both Normal Ratings and Emergency Ratings per the associated Operating Plans, to prevent equipment damage, to avoid public safety risks, and to mitigate other potential reliability impacts. Waiting to implement Operating Plans until after the time period associated with next highest Emergency Rating has been exceeded would not meet this goal. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

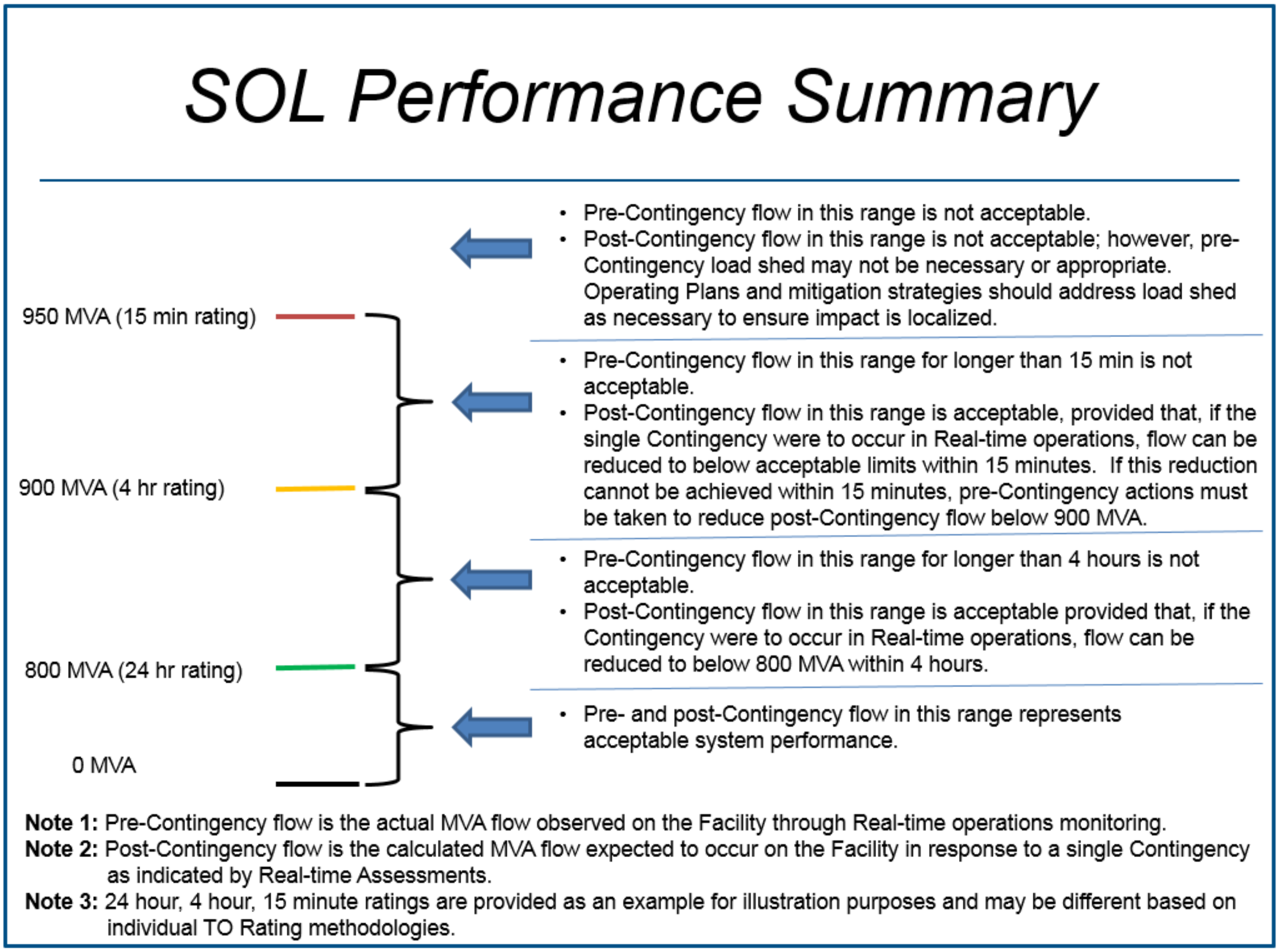

Figure 1. Facility Rating System Operating Limit Performance Summary

The following example scenarios describe appropriate operator action with respect to Figure 1:

1. **<u>Example 1 Scenario</u>** - System loads are increasing and actual flow on the line exceeds 800 MVA as shown in Figure 2. The System Operator is expected to take actions as necessary in accordance with the Operating Plan to ensure that flow is reduced to below 800 MVA within 4 hours. The Operating Plan may not require immediate operator action if loads are expected to decrease within the next hour as an example. In this case, the Operating Plan might require the TOP to monitor the flow and include other mitigating actions if the loading does not decrease as expected so that flow can be reduced to within the 800 MVA limit prior to the expiration of the 4 hours (assuming that Real-time Contingency Analysis (RTCA) does not indicate that a Contingency would result in this Facility exceeding the 950 MVA rating.) It is important to state that waiting until 3:45 min into a 4-hour rating to take actions might use up equipment life. So, while it is acceptable

operation for system performance, it may not be acceptable operation for the equipment owner to make use of the full 4-hour rating if actions were available to be taken.

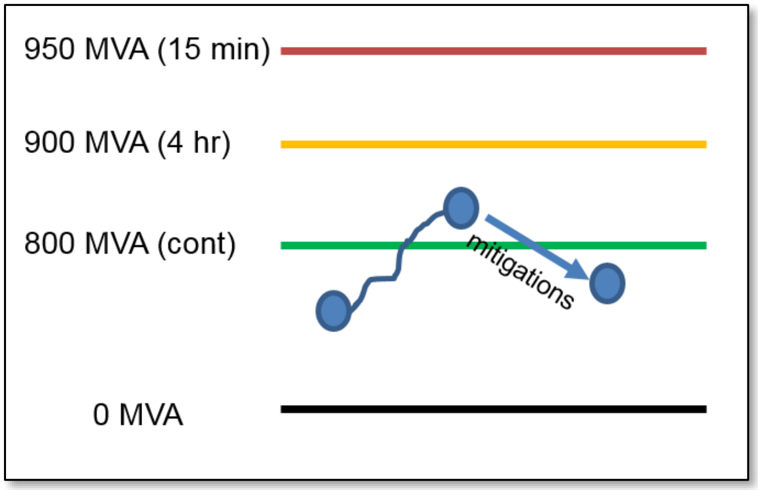

Figure 2. Example 1 Scenario – Pre-Contingency State

2. **<u>Example 2 Scenario</u>** - Flow on the line is 500 MVA. RTCA indicates that a single Contingency elsewhere in the system would cause flow on the line to immediately jump to 975 MVA. This condition represents unacceptable system performance for the post-Contingency state. Accordingly, the System Operator is expected to take action (pre-Contingency mitigation action) to reduce the post-Contingency flow such that RTCA no longer indicates that flow on this line would jump to a value higher than 950 MVA if the Contingency were to occur. Reference Figure 3 below for a pictorial of this scenario. In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, post-Contingency Operating Plans are not adequate, and TOPs are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 stable.

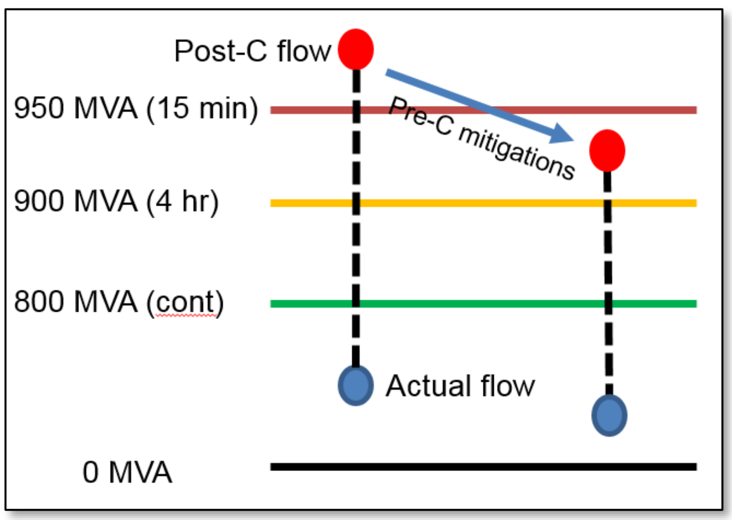

Figure 3. Example 2 Scenario – Unacceptable Post-Contingency State

3. **<u>Example 3 Scenario</u>** - Flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. If the Contingency were to occur, the System Operator would have 15 minutes to reduce flow on this line to an acceptable level. The acceptable level could be either 900 MVA or 800 MVA depending on how the line is rated based on the Transmission Owner's Facility Ratings methodology. If this information is not known, the System Operator should assume that flow would need to be reduced to below 800 MVA. If the Contingency actually occurs and the flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. For this scenario it is important for reliability that any post-Contingency Operating

Plans (i.e., any Operating Plans that are employed after an actual Contingency event occurs) can be fully implemented to reduce flows within 800MVA within 15 minutes to avoid equipment damage or unsafe line sagging. If it is determined that a post-Contingency Operating Plan is viable, then it is acceptable to remain in this state and to wait to take mitigating action if the Contingency were to actually occur. Operators would then increase monitoring of this Facility as part of the Operating Plan and to be prepared to take action if the Contingency event actually occurs. If it is determined that the post-Contingency Operating Plan is unable to reduce flow to acceptable levels within 15 minutes, then the System Operator must take pre-Contingency actions to reduce post-Contingency flows to below 900 MVA (i.e., take pre-Contingency action that result in RTCA indicating that a Contingency would result in flows below 900 MVA). Reference Figure 4 below for a pictorial of this scenario.

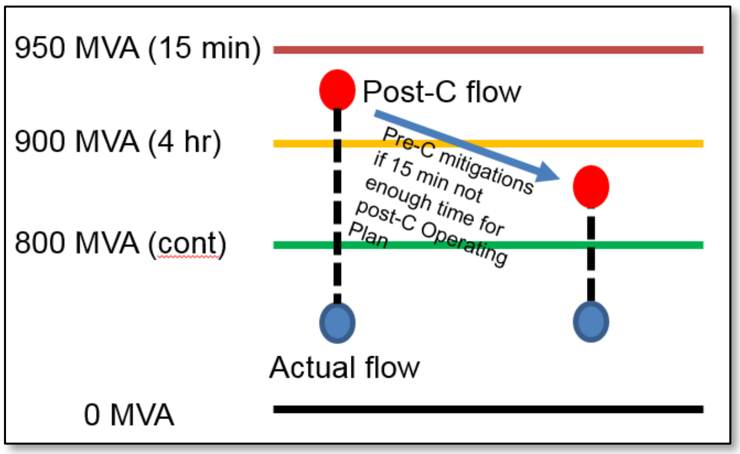

Figure 4. Example 3 Scenario – Post-Contingency State May Require pre-Contingency Mitigation

4. **Example 4 Scenario** - Similar to scenario 3, flow on the line is 500 MVA. RTCA indicates that if a single Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 925 MVA. The worst single Contingency event actually occurs, and as expected, flow on this line immediately jumps to 925 MVA. The System Operator has 15 minutes to reduce flow on this line to an acceptable level. If flow is not reduced to an acceptable level within 15 minutes, facilities could be damaged, or worse, the line could sag creating a public safety hazard. After the Contingency event actually occurs, the system is in a new state. Real-time Assessments are now performed on the new system state. The Real-time Assessment against this new state now indicates that if a Contingency elsewhere in the system were to occur, flow on this line would immediately jump to 975 MVA. At this point further mitigations must be made to bring post-Contingency flows below 950 MVA. Reference Figure 5 below for a pictorial of this scenario.

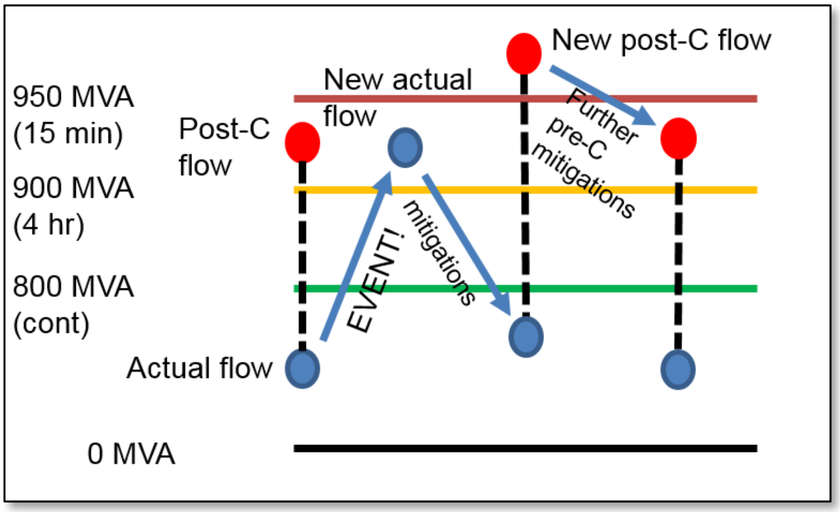

Figure 5. Example 4 Scenario – An Actual Contingency Event Occurs

Steady State Voltage Limit Exceedance

SOL performance for System Voltage Limits is determined through Operational Planning Analyses and through Real-time monitoring and Real-time Assessments. Normal and emergency System Voltage Limits are required to be established by the TOP in accordance with the RC's SOL methodology. FAC-011-4 Requirement R3 requires that the RC's SOL methodology contain specific requirements associated with the establishment of System Voltage Limits. Per FAC-011-4 Requirement R3, System Voltage Limits are required respect undervoltage load shedding relay settings and UVLS, to address coordination and common use of System Voltage Limits with neighbors, and to respect any equipment voltage limitations specified in the Transmission Owner's or the Generation Owner's Facility Ratings methodology per approved FAC-008-3.

Normal System Voltage Limits are typically applicable for the pre-Contingency state while emergency System Voltage Limits are normally applicable for the post-Contingency state. SOL exceedance with respect to these System Voltage Limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) System Voltage Limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside emergency System Voltage Limits in response to a Contingency event. System Voltage Limits are often established as normal and emergency high and low limits as depicted in the example in Figure 6. However, some TOPs might implement time-based System Voltage Limits as shown in the example in Figure 7. Any System Voltage Limit must be established in accordance with its RC's SOL methodology. Real-time Assessments should recognize the impact of automatically controlled reactive devices and whether or not those devices are sufficient without manual operator action for maintaining voltages within System Voltage Limits pre- or post-Contingency.

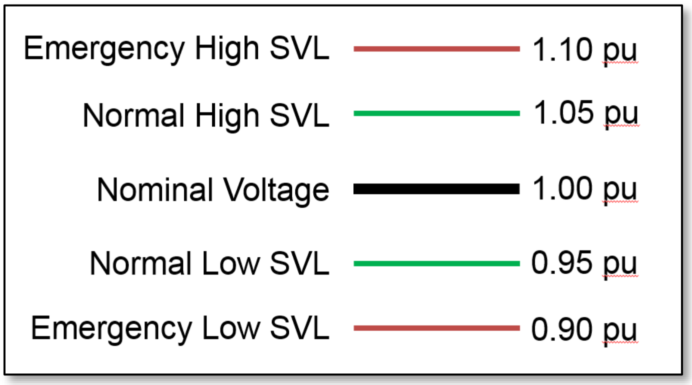

Figure 6. Example of a System Voltage Limit Set

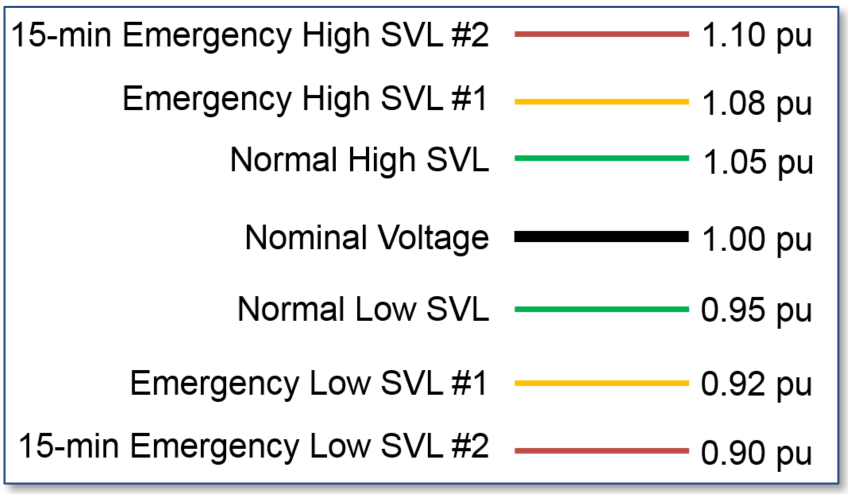

Figure 7. Example of a System Voltage Limit Set Utilizing Time-Based Values

Stability Limit Exceedance

Transient and voltage ~~S~~stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified limiting Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for ~~S~~stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Stability limits are defined to identify the point at which this would occur. Operating within defined stability limits prevents the associated Contingency (ies) from resulting in instability. Figure 8 depicts a wide-area's voltage Stability ~~performance exceeds~~performance exceeds an SOL that qualifies as an IROL. In this example, the SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

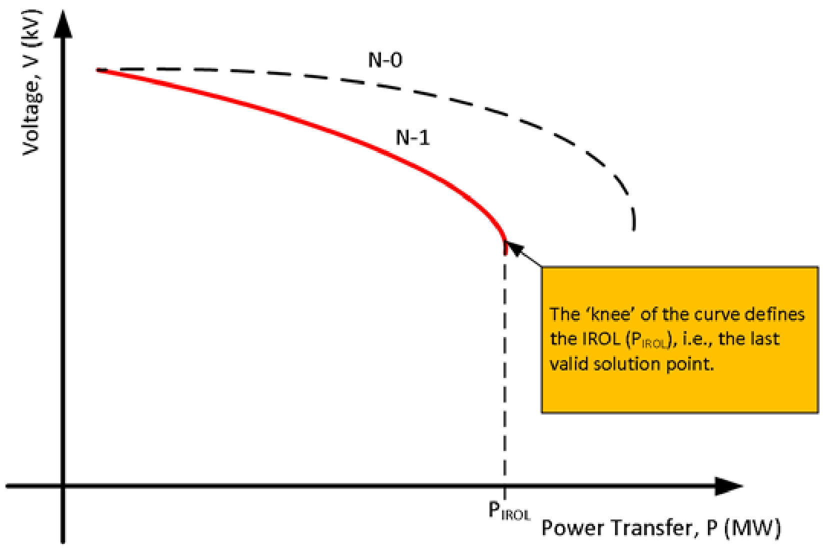

Figure 8. Voltage Stability System Operating Limit Performance Summary

SOL Exceedance and Operating Plans:

SOL exceedances occur when the performance framework described in proposed FAC-011-4 Requirement R6 is not being met; in Real-time operations, SOL exceedances are determined through Real-time monitoring and Real-time Assessments, while in the day-ahead space, potential SOL exceedances are determined through Operational Planning Analyses. For Facility Ratings and System Voltage Limits, SOL exceedances are identified through the evaluation of the pre-Contingency state and through an evaluation of Contingencies against that state. For stability limits, SOL exceedances are identified through system monitoring against defined stability limits or through the evaluation of stability performance against defined stability performance criteria.

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure acceptable BES performance is maintained, preventing SOL exceedances from escalating to a condition where the next Contingency could result in System instability, Cascading, or uncontrolled separation. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or SOLs identified above.

An example of a general Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.	Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in the specific Operating Plan.
Emergency (4 hr)	All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in the specific Operating Plan.	Use available effective actions and emergency procedures except Load shed consistent with timelines identified in the specific Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in the specific Operating Plan.	Take action (reconfigure, redispatch, etc. per the specific Operating Plan) to address the unacceptable post-Contingency condition. Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in the specific Operating Plan.

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts, generation output levels, Interchange, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Facility Ratings, and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning** – a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead, up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.

- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Final Ballot Open through April 28, 2021

Now Available

A 10-day final ballot is open through **8 p.m. Eastern, Wednesday, April 28, 2021** for the following standards and implementation plan:

- FAC-011-4 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 – Establish and Communicate System Operating Limit
- FAC-003-5 – Transmission Vegetation Management
- PRC-002-3 – Disturbance Monitoring and Reporting Requirements
- PRC-023-5 – Transmission Relay Loadability
- PRC-026-2 – Relay Performance During Stable Power Swings
- IRO-008-3 – Reliability Coordinator Operational Analyses and Real-time Assessments
- TOP-001-6 – Transmission Operations
- Implementation Plan

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-011-4 FN 4 ST
Voting Start Date: 4/19/2021 8:57:46 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 277
Total Ballot Pool: 323
Quorum: 85.76
Quorum Established Date: 4/19/2021 1:24:56 PM
Weighted Segment Value: 82.83

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	91	1	58	0.841	11	0.159	0	13	9
Segment: 2	8	0.8	5	0.5	3	0.3	0	0	0
Segment: 3	73	1	40	0.8	10	0.2	0	10	13
Segment: 4	15	1	10	1	0	0	0	1	4
Segment: 5	70	1	40	0.851	7	0.149	0	11	12
Segment: 6	54	1	31	0.775	9	0.225	0	8	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	323	6.6	191	5.467	41	1.133	0	45	46

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Abstain	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Grant Wilkerson		Negative	N/A
3	Westar Energy	Bryan Taggart		Negative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A

6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A

5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
3	AEP	Kent Feliks		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Negative	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A

10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Abstain	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A

1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
6	Edison International - Southern California Edison	Kenya Streeter		Negative	N/A

	Company				
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
3	Great River Energy	Michael		Affirmative	N/A

		Brytowski			
6	Great River Energy	Donna Stephenson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
3	CPS Energy	Glenn Pressler		None	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		None	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A

6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown	Jennifer Flandermeyer	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-014-3 FN 6 ST
Voting Start Date: 4/19/2021 8:58:05 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 6
Total # Votes: 272
Total Ballot Pool: 325
Quorum: 83.69
Quorum Established Date: 4/19/2021 1:25:18 PM
Weighted Segment Value: 92.34

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	92	1	70	0.909	7	0.091	0	5	10
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	74	1	52	0.945	3	0.055	0	3	16
Segment: 4	15	1	11	1	0	0	0	2	2
Segment: 5	70	1	50	0.909	5	0.091	0	3	12
Segment: 6	54	1	36	0.923	3	0.077	0	4	11
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.2	2	0.2	0	0	0	1	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	325	6.7	234	6.187	20	0.513	0	18	53

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		None	N/A
5	Manitoba Hydro	Yuguang Xiao		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A

3	Manitoba Hydro	Mike Smith		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Grant Wilkerson		None	N/A
3	Westar Energy	Bryan Taggart		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
5	Austin Energy	Michael Dillard		None	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A

3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
1	Black Hills Corporation	Seth Nelson		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A

6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
3	AEP	Kent Feliks		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
7	Luminant Mining Company LLC	James Watson		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A

1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A

6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A

3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
6	Modesto Irrigation District	James McFall		Abstain	N/A
6	Salt River Project	Bobby Olsen		None	N/A

4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Abstain	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Negative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A

6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Evergy	Thomas ROBBEN		Affirmative	N/A
1	Evergy	Allen Klassen		Affirmative	N/A
3	Evergy	Marcus Moor		Affirmative	N/A
5	Evergy	Derek Brown		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits FAC-003-5 FN 3 ST
Voting Start Date: 4/19/2021 8:58:21 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 287
Total Ballot Pool: 333
Quorum: 86.19
Quorum Established Date: 4/19/2021 1:25:38 PM
Weighted Segment Value: 93.75

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	96	1	65	0.867	10	0.133	0	8	13
Segment: 2	7	0.6	6	0.6	0	0	0	1	0
Segment: 3	75	1	56	0.918	5	0.082	0	3	11
Segment: 4	17	1	12	1	0	0	0	1	4
Segment: 5	74	1	51	0.911	5	0.089	0	7	11
Segment: 6	53	1	41	0.911	4	0.089	0	3	5
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	333	6.3	238	5.907	24	0.393	0	25	46

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey		Affirmative	N/A
3	AEP	Kent Feliks		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP	JT Kuehne		Negative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A

1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A

1	JEA	Joe McClung		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A

3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	None	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
10	New York State Reliability Council	ALAN ADAMSON	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
3	Lakeland Electric	Steve Marshall	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Don Stahl	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer	Abstain	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	Abstain	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar	Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A

4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder	Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter	Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
3	National Grid USA	Brian Shanahan	Affirmative	N/A
10	Midwest Reliability Organization	William Steiner	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Affirmative	N/A
3	Eversource Energy	Christopher McKinnon	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	David Heins	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	N/A

3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	NovaSource Power Services	Kristina Marriott		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
		Payam			

1	Hydro One Networks, Inc.	Farahbakhsh		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown	Jennifer Flandermeyer	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

NERC Balloting Tool

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Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-002-3 FN 3 ST
Voting Start Date: 4/19/2021 8:58:43 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 287
Total Ballot Pool: 332
Quorum: 86.45
Quorum Established Date: 4/19/2021 1:26:01 PM
Weighted Segment Value: 94.17

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	95	1	65	0.89	8	0.11	0	10	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	75	1	55	0.917	5	0.083	0	4	11
Segment: 4	17	1	12	1	0	0	0	1	4
Segment: 5	74	1	51	0.911	5	0.089	0	7	11
Segment: 6	53	1	40	0.909	4	0.091	0	4	5
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	332	6.4	237	6.027	22	0.373	0	28	45

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP	JT Kuehne		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A

1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
			Brandon		

1	Gainesville Regional Utilities	David Owens	McCormick	None	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A

5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
1	JEA	Joe McClung		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A

2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
		W. Dwayne			

3	Austin Energy	Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	None	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
3	Lakeland Electric	Steve Marshall	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Don Stahl	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer	Abstain	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar	Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan	Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith	Abstain	N/A

3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder	Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter	Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Affirmative	N/A
3	National Grid USA	Brian Shanahan	Affirmative	N/A
10	Midwest Reliability Organization	William Steiner	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Affirmative	N/A
3	Eversource Energy	Christopher McKinnon	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	David Heins	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Affirmative	N/A
	Southern Company - Southern Company Services,			

1	Inc.	Matt Carden		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	NovaSource Power Services	Kristina Marriott		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A

6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown	Jennifer Flandermeyer	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-023-5 FN 3 ST
Voting Start Date: 4/19/2021 8:59:03 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 287
Total Ballot Pool: 335
Quorum: 85.67
Quorum Established Date: 4/19/2021 1:26:39 PM
Weighted Segment Value: 93.55

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	95	1	64	0.865	10	0.135	0	9	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	76	1	55	0.917	5	0.083	0	5	11
Segment: 4	18	1	12	1	0	0	0	1	5
Segment: 5	74	1	49	0.907	5	0.093	0	8	12
Segment: 6	54	1	38	0.905	4	0.095	0	6	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	335	6.3	231	5.894	24	0.406	0	32	48

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP	JT Kuehne		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A

1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A

3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A

4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
1	JEA	Joe McClung		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A

2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A

1	Muscatine Power and Water	Andy Kurriger	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	None	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Don Stahl	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer	Abstain	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan	Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith	Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A

6	Snohomish County PUD No. 1	John Liang	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder	Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter	Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
3	Seattle City Light	Laurie Hammack	None	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Negative	N/A
5	Public Utility District No. 1 of Pend Oreille County	Tim McMaster	None	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
3	National Grid USA	Brian Shanahan	Affirmative	N/A
10	Midwest Reliability Organization	William Steiner	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	David Heins	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A

5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A

5	NovaSource Power Services	Kristina Marriott		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown	Jennifer Flandermeyer	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

[redacted]

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits PRC-026-2 FN 3 ST
Voting Start Date: 4/19/2021 8:59:23 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 287
Total Ballot Pool: 333
Quorum: 86.19
Quorum Established Date: 4/19/2021 1:27:04 PM
Weighted Segment Value: 94.18

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	95	1	67	0.893	8	0.107	0	8	12
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	75	1	55	0.917	5	0.083	0	4	11
Segment: 4	17	1	12	1	0	0	0	1	4
Segment: 5	74	1	51	0.911	5	0.089	0	7	11
Segment: 6	54	1	39	0.907	4	0.093	0	5	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	333	6.4	238	6.028	22	0.372	0	27	46

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
6	AEP	JT Kuehne		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A

1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	None	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A

3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Seth Nelson		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Abstain	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Truong Le	None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Beaches Energy Services	Carolyn Woodard	Brandon McCormick	None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A

4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
1	JEA	Joe McClung		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A

6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Truong Le	Negative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Edison International - Southern California Edison	Romel Aquino		Affirmative	N/A

	Company			
4	CMS Energy - Consumers Energy Company	Aric Root	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	None	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Don Stahl	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	James Watson	None	N/A
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
3	Lakeland Electric	Steve Marshall	None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene	Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer	None	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar	Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway	None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan	Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith	Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A

6	Snohomish County PUD No. 1	John Liang	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Manitoba Hydro	Mike Smith	Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder	Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter	Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones	None	N/A
3	Seattle City Light	Laurie Hammack	None	N/A
6	Public Utility District No. 1 of Pend Oreille County	April Owen	None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu	Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
10	Midwest Reliability Organization	William Steiner	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston	Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry	Abstain	N/A
3	Eversource Energy	Christopher McKinnon	Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason	Affirmative	N/A
3	JEA	Garry Baker	None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel	None	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson	None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh	Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue	Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson	Affirmative	N/A
1	NB Power Corporation	Nurul Abser	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz	Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	None	N/A
3	Omaha Public Power District	David Heins	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Affirmative	N/A
	Southern Company - Southern Company Services,			

1	Inc.	Matt Carden		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	NovaSource Power Services	Kristina Marriott		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A

6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown	Jennifer Flandermeyer	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

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NERC Balloting Tool

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Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits IRO-008-3 FN 2 ST
Voting Start Date: 4/19/2021 8:59:45 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 220
Total Ballot Pool: 233
Quorum: 94.42
Quorum Established Date: 4/19/2021 1:27:21 PM
Weighted Segment Value: 89.59

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	64	1	48	0.923	4	0.077	0	8	4
Segment: 2	6	0.6	6	0.6	0	0	0	0	0
Segment: 3	52	1	39	0.886	5	0.114	0	6	2
Segment: 4	11	0.9	8	0.8	1	0.1	0	2	0
Segment: 5	52	1	34	0.872	5	0.128	0	8	5
Segment: 6	41	1	27	0.794	7	0.206	0	5	2
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	4	0.3	3	0.3	0	0	0	1	0
Totals:	233	6	167	5.375	22	0.625	0	31	13

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Neil Shockey		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A

3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
6	AEP	JT Kuehne		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Westar Energy	James McBee		Negative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
		Aaron			

3	FirstEnergy - FirstEnergy Corporation	Ghodooshim		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Abstain	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A

5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A

3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A

6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits TOP-001-6 FN 2 ST
Voting Start Date: 4/19/2021 9:00:07 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 235
Total Ballot Pool: 250
Quorum: 94
Quorum Established Date: 4/19/2021 1:27:40 PM
Weighted Segment Value: 87.93

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	72	1	53	0.883	7	0.117	0	7	5
Segment: 2	6	0.6	6	0.6	0	0	0	0	0
Segment: 3	55	1	43	0.86	7	0.14	0	3	2
Segment: 4	12	1	11	0.917	1	0.083	0	0	0
Segment: 5	55	1	38	0.826	8	0.174	0	4	5
Segment: 6	43	1	28	0.778	8	0.222	0	4	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	4	0.3	3	0.3	0	0	0	1	0
Totals:	250	6.1	184	5.364	31	0.736	0	20	15

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Neil Shockey		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Negative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A

5	AEP	Thomas Foltz		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
6	AEP	JT Kuehne		Abstain	N/A
3	Eversource Energy	Christopher McKinnon		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway	Mark Pratt	Negative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A

5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Michael Courchesne	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Truong Le	Negative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Westar Energy	James McBee		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
	Edison International - Southern California Edison				

3	Company	Romel Aquino		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	None	N/A
6	Southeastern Power Administration	Douglas Spencer		None	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	Truong Le	Negative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Truong Le	Negative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Truong Le	Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer		Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
5	NovaSource Power Services	Kristina Marriott		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	N/A

5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A

2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Negative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		None	N/A
6	Evergy	Thomas ROBBEN	Jennifer Flandermeyer	Affirmative	N/A
1	Evergy	Allen Klassen	Jennifer Flandermeyer	Affirmative	N/A
3	Evergy	Marcus Moor	Jennifer Flandermeyer	Affirmative	N/A
5	Evergy	Derek Brown		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits Implementation Plan FN 5 OT
Voting Start Date: 4/19/2021 9:00:36 AM
Voting End Date: 4/28/2021 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 5
Total # Votes: 274
Total Ballot Pool: 324
Quorum: 84.57
Quorum Established Date: 4/19/2021 1:28:26 PM
Weighted Segment Value: 93.01

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	92	1	67	0.893	8	0.107	0	6	11
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	75	1	49	0.925	4	0.075	0	5	17
Segment: 4	14	1	9	0.9	1	0.1	0	2	2
Segment: 5	71	1	53	0.93	4	0.07	0	4	10
Segment: 6	54	1	38	0.905	4	0.095	0	4	8
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	3	0.1	1	0.1	0	0	0	1	1

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	324	6.4	230	5.952	21	0.448	0	23	50

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Abstain	N/A
6	Westar Energy	Grant Wilkerson		None	N/A
3	Westar Energy	Bryan Taggart		None	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Avani Pandya		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		None	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A

3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	N/A

5	City Water, Light and Power of Springfield, IL	John Kennedy		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
3	Black Hills Corporation	Don Stahl		None	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
3	AEP	Kent Feliks		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	N/A
6	Entergy	Julie Hall		None	N/A
1	LS Power Transmission, LLC	Darin Ferguson		None	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder		Negative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
5	Lakeland Electric	Becky Rinier		None	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A

1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Colorado Springs Utilities	Melissa Brown		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	Elizabeth Davis	Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
6	Seattle City Light	Brian Belger		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	Truong Le	Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		None	N/A

5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		None	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		None	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A

6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	CPS Energy	Gladys DeLaO		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Florida Municipal Power Agency	Dale Ray	Truong Le	Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
1	TECO - Tampa Electric Co.	Regan Haines		None	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Bratkovic		None	N/A
1	GridLiance Holdco, LP	Randy Cleland		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

5	Pacific Gas and Electric Company	Ed Hanson	Pamalet Mackey	None	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Pamalet Mackey	None	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
6	Evergy	Thomas ROBBEN		Affirmative	N/A
1	Evergy	Allen Klassen		Affirmative	N/A
3	Evergy	Marcus Moor		Affirmative	N/A
5	Evergy	Derek Brown		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey		Affirmative	N/A

NERC Glossary Definition: System Operating Limit

Term: “System Operating Limit”

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3).
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2).
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3).
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2).

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with

requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts. Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.

These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.

2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.

3. The TOP would communicate those SOLs to System Operators.

4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO

standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that “provide” for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL “provided” for reliable pre- and post-Contingency operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the “Project 2014-03 Whitepaper”), which developed the currently-effective Transmission Operations (“TOP”) and Interconnection Reliability Operations and Coordination (“IRO”) Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to “bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.” The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC’s Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance (“FAC”) group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the Project 2014-03 Whitepaper provided clarity on the SOL concept,

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the SDT posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use

maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase “used in Bulk Electric System operations” to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed requirement R6 in proposed Reliability Standard FAC-014-3 to address that issue.

As discussed in detail below, the SDT determined that references to “most limiting criteria” and “acceptable reliability criteria”, and the manner in which the “specified system configuration” and the “pre- and post-contingency” phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the “most limiting criteria” concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the “most limiting criteria.” Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the “most limiting criteria” concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing “most

limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

<u>Acceptable Reliability Criteria</u> – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

<u>Specified System Configuration</u> – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

<u>Pre- and Post-Contingency</u> – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3).
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2).
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3).
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2).

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with

requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts. Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.

These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.

2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.

3. The TOP would communicate those SOLs to System Operators.

4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

review team recognized that while the Project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the SDT posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and stability criteria used in planning with those used in operations. The SDT developed requirement R6 in proposed Reliability Standard FAC-014-3 to address that issue.~~The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.~~

As discussed in detail below, the SDT determined that references to "most limiting criteria" and "acceptable reliability criteria", and the manner in which the "specified system configuration" and the "pre- and post-contingency" phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria." Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

Acceptable Reliability Criteria – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

Specified System Configuration – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

Pre- and Post-Contingency – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for

the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

Standards Announcement

Project 2015-09 Establish and Communicate System Operating Limits

Final Ballot Open through May 10, 2021

Now Available

A 10-day final ballot is open through **8 p.m. Eastern, Monday, May 10, 2021** for the following definitions:

- Proposed Definition of System Operating Limit (SOL)
- Proposed Definition of System Voltage Limit

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the definitions will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Latrice Harkness (via email) or at 404-446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits Proposed Definition - System Operating Limit FN 2 DEF
Voting Start Date: 4/29/2021 9:27:52 AM
Voting End Date: 5/10/2021 8:00:00 PM
Ballot Type: DEF
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 269
Total Ballot Pool: 300
Quorum: 89.67
Quorum Established Date: 4/29/2021 10:22:19 AM
Weighted Segment Value: 86.43

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	64	0.853	11	0.147	0	5	7
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	46	0.852	8	0.148	0	5	9
Segment: 4	16	1	10	0.833	2	0.167	0	0	4
Segment: 5	63	1	46	0.836	9	0.164	0	2	6
Segment: 6	49	1	31	0.816	7	0.184	0	6	5
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	5	0.5	5	0.5	0	0	0	0	0
Totals:	300	6.7	213	5.791	38	0.909	0	18	31

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
6	AEP	JT Kuehne		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A

1	Ameren - Ameren Services	Tamara Evey		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Abstain	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
6	Entergy	Julie Hall		Negative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Kevin Conway		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A

1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
6	New York Power Authority	Erick Barrios		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
1	Black Hills Corporation	Seth Nelson		Negative	N/A
1	Portland General Electric Co.	Brooke Jockin		Negative	N/A
3	Portland General Electric Co.	Dan Zollner		Negative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		None	N/A
5	Lakeland Electric	Becky Rinier		Negative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Abstain	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	N/A
1	SaskPower	Wayne Guttormson		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
3	Public Utility District No. 1 of Pend Oreille County	David Hodder		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A

1	Duke Energy	Laura Lee		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster	Brandon McCormick	Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
1	JEA	Joe McClung		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Tammy Porter	None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Daniel Valle	Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Negative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A

3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		Affirmative	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao	Helen Zhao	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A

4	Austin Energy	Jun Hua	Affirmative	N/A
1	Seattle City Light	Michael Jang	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding	Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
3	Austin Energy	W. Dwayne Preston	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger	Abstain	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	Affirmative	N/A
4	Seattle City Light	Hao Li	Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	Abstain	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	Platte River Power Authority	Tyson Archie	Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	None	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Abstain	N/A
5	Omaha Public Power District	Mahmood Safi	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	None	N/A
2	New York Independent System Operator	Gregory Campoli	Negative	N/A
3	Lakeland Electric	Steve Marshall	Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl	Affirmative	N/A
3	Black Hills Corporation	Don Stahl	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	Negative	N/A
6	Luminant - Luminant Energy	Kris Butler	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung	Affirmative	N/A
7	Luminant Mining Company LLC	James Watson	Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield	Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck	Affirmative	N/A
5	Vistra Energy	Dan Roethemeyer	Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	None	N/A
3	WEC Energy Group, Inc.	Thomas Breene	None	N/A

5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
3	Eversource Energy	Christopher McKinnon		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A

5	Lincoln Electric System	Kayleigh Wilkerson	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke	Negative	N/A
3	Omaha Public Power District	David Heins	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
5	Salt River Project	Kevin Nielsen	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells	Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
3	Salt River Project	Zack Heim	Negative	N/A
5	Southern Company - Southern Company Generation	James Howell	Affirmative	N/A
1	Lincoln Electric System	Josh Johnson	Affirmative	N/A
1	Exelon	Daniel Gacek	Negative	N/A
3	Exelon	Kinte Whitehead	Negative	N/A
5	Exelon	Cynthia Lee	Negative	N/A
6	Exelon	Becky Webb	Negative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott	Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	N/A
1	Salt River Project	Chris Hofmann	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Affirmative	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
6	Salt River Project	Bobby Olsen	None	N/A
1	Platte River Power Authority	Matt Thompson	Affirmative	N/A
2	California ISO	Jamie Johnson	Affirmative	N/A
1	Austin Energy	Thomas Standifur	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative	N/A

Ballot Results

Ballot Name: 2015-09 Establish and Communicate System Operating Limits System Voltage Limit | New Definition FN 2 DEF
Voting Start Date: 4/29/2021 9:26:49 AM
Voting End Date: 5/10/2021 8:00:00 PM
Ballot Type: DEF
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 286
Total Ballot Pool: 306
Quorum: 93.46
Quorum Established Date: 4/29/2021 10:22:28 AM
Weighted Segment Value: 76.93

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	58	0.795	15	0.205	0	10	6
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	69	1	44	0.746	15	0.254	0	6	4
Segment: 4	14	1	9	0.75	3	0.25	0	0	2
Segment: 5	66	1	40	0.714	16	0.286	0	7	3
Segment: 6	50	1	26	0.65	14	0.35	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment: 9	1	0	0	0	0	0	0	0	1
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	306	6.7	192	5.155	65	1.545	0	29	20

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
3	Salt River Project	Zack Heim		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A

6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold	Amy Casuscelli	Affirmative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		Negative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Cristhian Godoy		Negative	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Duan Gavel		Affirmative	N/A
3	Austin Energy	W. Dwayne		Affirmative	N/A

		Preston		
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	N/A
5	NB Power Corporation	Rob Vance	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia	Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey	Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia	Affirmative	N/A
3	Lincoln Electric System	Jason Fortik	Negative	N/A
1	Portland General Electric Co.	Brooke Jockin	Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman	Affirmative	N/A
1	IDACORP - Idaho Power Company	Mike Marshall	Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood	Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Randhir Singh	Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins	Negative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith	Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Affirmative	N/A
6	Black Hills Corporation	Brooke Voorhees	None	N/A
6	Xcel Energy, Inc.	Carrie Dixon	Affirmative	N/A
5	Seattle City Light	Faz Kasraie	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
1	Western Area Power Administration	sean erickson	Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke	Negative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte	Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Ann Carey	Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Colleen Campbell	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle Longo	Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen	Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld	Affirmative	N/A

6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
6	Exelon	Becky Webb		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	John Kennedy		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Jeremy Lorigan		Negative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		Abstain	N/A
3	Black Hills Corporation	Don Stahl		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Negative	N/A
3	AEP	Kent Feliks		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Aidan Gallegos		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	LS Power Transmission, LLC	Darin Ferguson		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
5	Kissimmee Utility Authority	Jay Butters		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A

3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
6	Muscatine Power and Water	Nick Burns		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
4	Georgia System Operations Corporation	Benjamin Winslett		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Negative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
5	Lakeland Electric	Becky Rinier		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
1	Lower Colorado River Authority	James Baldwin		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
3	Santee Cooper	James Poston		Abstain	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
5	Black Hills Corporation	Derek Silbaugh		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Ginette Lacasse		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	N/A
5	Puget Sound Energy, Inc.	Lynn Murphy		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Colorado Springs Utilities	Melissa Brown		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Peak Reliability	Scott Downey		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
6	Seattle City Light	Brian Belger		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
3	Seattle City Light	Laurie Hammack		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
6	AEP	JT Kuehne		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	N/A

10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Trena Haynes		Negative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
6	Basin Electric Power Cooperative	Jerry Horner		Negative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Basin Electric Power Cooperative	Colleen Peterson		Negative	N/A
1	Puget Sound Energy, Inc.	Chelsey Neil		Affirmative	N/A

1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Puget Sound Energy, Inc.	Nicolas Pacholski		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	Modesto Irrigation District	Roderick Cook		None	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
6	Modesto Irrigation District	James McFall		None	N/A
6	Salt River Project	Bobby Olsen		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
3	City of Farmington	Linda Jacobson-Quinn		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
1	CPS Energy	Gladys DeLaO		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A

[redacted]

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit I

Standard Drafting Team Roster
Project 2015-09 Establish and Communicate System Operating Limits

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2015-09 Establish and Communicate System Operating Limits

	Name	Entity
Chair	Dean LaForest	ISO New England
Vice Chair	Hari Singh	Xcel Energy
Members	Samuel Jager	Independent Electricity System Operator
	Thomas Leslie	Georgia Transmission Corp
	Stephen Solis	Electric Reliability Council of Texas
	Aaron Staley	Orlando Utilities Commission
	Dede Subakti	California ISO
PMOS Liaison	Ken Lanehome	Bonneville Power Administration
NERC Staff	Latrice Harkness – Senior Standards Developer	North American Electric Reliability Corporation
	Darrel Richardson – Principal Technical Advisor, Standards	North American Electric Reliability Corporation
	Shamai Elstein – Assistant General Counsel	North American Electric Reliability Corporation